# DOCUMENT TITLE:
# Early Reservoir Appraisal Utilizing a Well Testing System

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# RPSEA PROJECT TITLE:
# Early Reservoir Appraisal Utilizing a Well Testing System

RPSEA Project No.: 08121-2501-02

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# ABSTRACT

This report summarizes the information gathered from the Research Partnership to Secure Energy for America (RPSEA) Project, *Early Reservoir Appraisal Utilizing a Well Testing System,* project - 08121-2501.

Nautilus International LLC., was awarded a contract with the objective to gain knowledge concerning the early reservoir appraisal using well testing systems. This is part of RPSEA's Prime Contract DE-AC26-07NT42677 issued by the U.S. Department of Energy.

A major RPSEA ultra-deep water (UDW) strategic theme is early appraisal of a reservoir with minimum drilling in order to reduce the risk associated with planning an economic reservoir development. Deepwater well testing in the Gulf of Mexico (GoM) is not economically viable or practical, primarily due to the high cost of conventional equipment and environmental and safety risks. A team of subject matter experts, whose experience covers many technical disciplines, was assembled to address the issues involved with deepwater well testing for early reservoir appraisal. The project started with extensive analyses and well test simulations for three major reservoir geological plays in the GoM to determine the reservoir and fluid characteristics. The reservoir modeling led to the design of eight well testing systems that can be used for short-term, long-term, interference, and injection testing. Each system was analyzed for operational feasibility in reference to subsea and surface safety systems, and vessel requirements, with the focus of reducing risks to personnel, the environment, equipment, and complying with all applicable regulations. Hardware fabrication and vessel construction are outside the scope of this project.

The reservoir analysis provides industry professionals with guidance as to which well test method will offer the best results in terms of the type of well test to perform, what the duration and flow rate will be, and estimations on the expected outcomes in order to better characterize the reservoir. The well test system architectural designs and operational feasibility analysis gives industry professionals all the available options for deepwater well testing in regards to downhole, subsea, surface, and vessel requirements, with an extensive focus on safety requirements. Providing this information to industry professionals and operators allows for more accurate decisions when justifying the production capacity and commerciality of a field / reservoir.

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# EXECUTIVE SUMMARY

The goal for well testing in the early reservoir appraisal stage is to gather information to help determine the economic potential of field discoveries and provide insights to safely commercialize the fields. This project provides options for deepwater well testing of reservoirs in the GoM.

The first aspect of this project was to perform detailed reservoir analysis and well test modeling on three major reservoir plays (Middle Miocene, Lower Tertiary Paleocene, and Lower Tertiary Eocene) in the GoM. Historical production data and expert assumptions were used to develop a catalog of the reservoir and fluid characteristics for each reservoir.

Well test simulations, utilizing short-term, long-term, interference, and injection testing were performed on each reservoir. Nodal analysis, which estimates the temperature and pressure not only at the wellhead but also at the surface, was performed for both the short-term and long-term tests for various rates and reservoir parameters. The goal was to understand the reservoir characteristics, the duration for different well tests, and pressure, flow rate, and fluid production properties during the well test.

The information gathered proved extremely valuable for industry professionals to design well test scenarios. The differences in water depth, rock formation, permeability, viscosity, gas to oil ratio (GOR), and bottom-hole pressure (BHP) are just a few parameters that have significant impact on the selection of a well test method and downhole / subsea / surface well testing equipment.

The simulation / modeling analysis produced significant results that provide cost benefits and environmental safeguards. The simulation results from conventional well testing (short-term, long-term, and interference testing) show that a substantial reduction in flow rate during well testing produced the same results as using maximum flow rates. The lower flow rates mean less produced fluids (oil, water, and gas) return to the surface, thus reducing the storage and disposal requirements.

The injection test simulation results were very encouraging. The final data correlates to the results of the conventional production tests and the injection tests require less time compared to the duration of conventional tests. One of the most important advantages of the injection test is there is no *live oil* (i.e., oil with dissolved gas) produced to the surface. This reduces environmental concerns regarding the flaring of gas at the surface and eliminates the need to store or off-load produced oil. The findings of the injection test warrant further investigation, beyond the scope of this study, to ensure that these tests can be used as a viable alternative to the conventional well tests.

Of all three reservoirs, the Middle Miocene has the highest permeability rocks (i.e., very porous) and lowest viscosity fluid (i.e., more like water compared to syrup). The Miocene reservoir size is moderate and the quality of sand is better than the other two reservoirs. Well testing designs for the Middle Miocene have the most favorable conditions in terms of test duration and fluid production.

The Lower Tertiary Paleocene reservoir is very deep, has the lowest rock permeability, and highest viscosity fluid among the three reservoirs. For the Paleocene, well testing will be challenging and will require longer test durations. For this reason, certain well test methods may not be practical in terms of time and cost. The low permeability, high viscosity, and depth in this reservoir also predict the need for additional equipment to push the production fluids to the surface (i.e., electric submersible pump [ESP], gas lift).

The Eocene reservoir has moderate permeability and viscosity. This places the Eocene second in terms of well testing feasibility. However, the higher GOR fluid properties in this reservoir need to be carefully managed (i.e., equipment selection, operational procedures, etc.).

The second aspect of this project was to architecturally design well testing systems that can be used in the GoM. Many multi-disciplinary subject matter experts were involved in this aspect of the project. The goal was to determine the operational feasibility of the well test systems with a major focus on ensuring safety (e.g., personnel, environment, and equipment). Three criteria were used to develop the well testing systems; subsea connection type (i.e., wellhead or subsea tree), riser type (i.e., conventional risers, flexible risers, and self standing risers [SSR]), and vessel type (i.e., mobile offshore drilling unit [MODU], floating production storage offloading vessel [FPSO], floating production unit [FPU] intervention vessels, installation vessels, or a combination of vessels). From these three criteria, eight well test systems were designed and the feasibility of each system was assessed.

Feasibility analysis for each of the eight systems included downhole, subsea, and surface safety mechanisms to shut-in the well, provide emergency disconnect capability, and ensure environmental and personnel safeguards. Detailed operational procedures, issues, control philosophies, and emergency disconnect sequence (EDS) descriptions and flowcharts were developed for each system. The different components in each system were rated and recommendations were made based on safety aspects of the feasibility analysis. A technical readiness level (TRL) analysis was conducted for each of the eight systems via a workshop that included subject matter experts from different disciplines involved throughout this study. Through this workshop, guided by an independent moderator, five of the eight systems were rated at the top of the industry accepted TRL scale. The remaining three systems had lower scores based cost and greater requirements for operational readiness.

Since each reservoir provides different parameters for well testing, an extensive analysis was done on the vessel deck equipment needed for each well test system based on the reservoir. This work included safety analysis for emergency shutdown (ESD) and pressure relief devices, pressure and velocity analysis for the produced fluids (oil, gas, and water), Pipeflo program schematics for the produced fluids traveling up from the wellhead through the vessel equipment, deck loading capacity for the equipment, and Flaresim program models to define the noise, radiation, and temperature effects under various wind conditions.

Deepwater GoM is a high risk, high prize region where every bit of information is important for a successful field development. Well tests provide invaluable information that cannot be acquired otherwise. The selection of a well testing method(s) is dependent on the field development phase and complexity of the reservoir.

The decision on which well test system to use is at the discretion of the operators. This project provides all the options and related information necessary for informed decisions to be made. The goal is for operators to use all this information to conduct early reservoir appraisal deepwater well testing to rapidly assess geological and reservoir attributes to determine the production capacity and economic feasibility of the field.

An enormous amount of multi-discipline data has been collected and analyzed from numerous sources and industry professionals during this project. To better improve the decision-making capabilities for the oil industry, it became apparent that all this valuable data must be available in an easy to use manner. As part of the business plan, a future deliverable resulting from this project is to provide a computer-based modeling tool used by industry professionals to determine the optimum well testing methods based on the type of reservoir, subsea and surface equipment, and vessel(s) criteria.

The overarching goal of this project was to provide safe, environmentally sound options for deepwater well testing in the GoM. The results of this project have delivered a variety of choices for deepwater well testing.

# 1 GENERAL

## 1.1 DOCUMENT SCOPE

This document summarizes the design and analysis work for RPSEA Project 08121-2501 *Early Reservoir Appraisal Utilizing a Well Testing System.*

The information within this report has been collected from the various tasks that make up the deliverables for the design and analysis phase of this project.

The original scope of this project was modified by RPSEA and the Operator Committee to:

- Investigate three reservoirs instead of five.
- Include injection testing.

Included in this document is a high-level description of a future effort, a web-based computer simulation model that can be used by various industry professionals to determine the best well testing scenario based on their needs (i.e., reservoir / well location and depth, vessel and equipment availability, and estimated costs).

Table 1 lists all the tasks involved with Project 08121-2501 and specifies the details of each task.

**Table 1:
Project 2501 Task List and Status**

| Task No. | Task Title with Status and Comments |
|---|---|
| 1 | Project Management Plan - Completed. |
| 2 | Technology Status Assessment - Completed:<br>Task Report Finalized 07 June 2010 (Document No.: 2501-TASK2.001)<br><br>Early reservoir appraisal technology status assessment provides an up-to-date review of deepwater testing of a subsea well with a wellhead or subsea production tree. The assessment was based on extensive research by the University of Tulsa, petroleum abstracts, and interviews with industry experts. |
| 3 | Technology Transfer Plan - Completed. |
| 4 | Routine Reports and Other Meetings – On-going. |
| 5 | Reservoir Well Testing: Task - Completed:<br>Report Finalized 05 October 2010 (Document No.: 08121-2501-02.05.Final).<br>Three types of reservoirs were selected for well testing modeling; Middle Miocene, Lower Tertiary Paleocene, and Lower Tertiary Eocene. Detailed well test modeling consisted of the following well test types; short term test, long term test, nodal analysis, and interference test. Based on RPSEA Technical Committee feedback, injection testing was also included. The main objectives were to understand the best well testing design / methods for each of the selected reservoirs. |
| 6.1 | Well Testing System Architecture and Conceptual Design - Completed (refer to Appendix A):<br>This task established the conceptual design and feasibility for well testing systems in the GoM. The functional and operational requirements for each of the eight well testing systems included surface and subsea control system, flow assurances, and equipment needed. This task also identified the available vessels in the GoM, the surface facilities and emergency disconnect requirements needed. Assessments on the safety and environmental conditions were completed for each system. Generalized cost estimates for each well testing system, vessel(s), and components will be reported on as the information becomes available. |

| Table 1: Project 2501 Task List and Status | |
|---|---|
| **Task No.** | **Task Title with Status and Comments** |
| 6.2 | Well Testing Operational Scenarios - Completed (Refer to Appendix A for a complete list of documents):<br>For the various well test systems, the operating, maintenance, and basic contingency plans and procedures are described. This includes facility equipment, deck handling, deployment of the well test riser, and performing various in-service (downhole) operations. |
| 6.3 | Technical Readiness Workshop - Completed:<br>The Technology Readiness Level (TRL) assessment provides the maturity status of the major components comprising each well test system. The TRL identified where further technical development is required for each system to enable its operation or to improve the projected performance of each well test system. Detailed explanation of TRL levels are in Appendix B. |
| 6.4 | Business Case and Commercialization Plan – Completed (subject to approval by the Steering Committee): Developed business case and commercialization plan for mobilizing the respective well test systems to a field ready status. |

## 1.2 ACRONYMS

| Acronym | Definition |
|---|---|
| ABS | American Bureau of Shipping |
| AHTS | Anchor handling tug supply (floater vessel to receive production crude) |
| API | American Petroleum Institute |
| BHP | Bottom hole pressure |
| BHTA | Bottom hole tool assembly |
| BOEMRE | Bureau of Ocean Energy Management, Regulation, and Enforcement |
| BOP | Blowout preventer |
| CGR | Condensate gas ratio |
| CRETIB | Corrosive, Reactive, Explosive, Toxic, Flammable, and Biological-infectious – Code / regulations in reference to hazardous waste containment and disposal). |
| CT | Coiled tubing |
| DP | Dynamic positioning |
| DST | Drill stem test (i.e., short-term test) |
| EDP | Emergency disconnect package |
| EDS | Emergency disconnect sequence (sequence includes shut-in the well and disconnect) |
| EPA | Environmental Protection Agency |
| ESD | Emergency shutdown (shut-in the well, but no disconnect) |
| ESP | Electric submersible pump |
| EWT | Extended well test (i.e., long-term test) |
| FDPSO | Floating drilling production storage offloading - vessel |
| FPSO | Floating drilling production offloading - vessel |
| GMC | General Marine Contractors |
| GoM | Gulf of Mexico |
| GOR | Gas oil ratio |

| Acronym | Definition |
|---|---|
| HPU | Hydraulic power unit |
| HS&E | Health Safety and Environment |
| LMRP | Lower marine riser package |
| MARECSA | Marítima de Ecología S.a. de C.V. |
| MDT | Modular formation dynamic tester |
| MODU | Mobile offshore drilling unit (i.e., drill ships and semisubmersibles) |
| MSV | Multi-support vessel |
| NEMA | National Electrical Manufacturers Association |
| OOIP | Original oil in place |
| OTC | Offshore Technology Conference |
| PLET | Pipeline end termination |
| PTA | Pressure transient analysis |
| RFP | Request for Proposal |
| ROV | Remotely operated vehicle |
| RPSEA | Research Partnership to Secure Energy for America |
| SBOP | Surface blowout preventer |
| SCM | Surface control module |
| SCSSV | Surface controlled subsurface safety valve |
| SFH | Surface flow head |
| SPE | Society of Petroleum Engineers |
| SPS | Surface production shut-off |
| SSA | Seafloor shut-off assembly |
| SSD | Seafloor shutoff device |
| SSOD | Subsea shut-off device |
| SSR | Self standing riser |
| SSTT | Subsea test tree |
| TCP | Tubing conveyed perforating (i.e. type of gun) |
| THRT | Tubing hanging running tool |
| TRL | Technical Readiness Level |
| TVD | Total vertical depth |
| UBJ | Umbilical junction box |
| UDW | Ultra deep water |
| USCBP | US Customs and Border Patrol |
| USCG | United States Coast Guard |
| VIV | Vortex induced vibration |
| WAV | Well access valve |
| WIV | Well intervention vessel |
| WTSV | Well testing services vessels – (DP2 FPSO vessel) |

## 1.3 UNITS OF MEASURE

| UOM | Definition | UOM | Definition |
|---|---|---|---|
| bbl | barrel | mD | Millidarcy |
| BBOE | Billion barrels of oil equivalent | MMBOE | Million barrels of oil equivalent |
| BOPD | Billion barrels of oil per day | MMbbl | Million barrels |
| BPD | Barrels per day | MMBOPD | Million barrels of oil per day |
| centipose | cp | MMscf | Million standard cubic foot |
| F° | Fahrenheit | MMscf/d | Million standard cubic foot per day |
| ft | Feet | MMstb | Million stock tank barrels |
| hr | Hour | MSTB | Thousand stock tank barrels |
| in | Inch | psi | Pounds per square inch |
| lb | Pound | psia | Pounds per square inch absolute |
| m | Meter | STB/D | Stock tank barrels per day |

## 1.4 DEFINITIONS

| Word / phrase | Definition |
|---|---|
| Bubble Point | The pressure and temperature conditions at which the first bubble of gas comes out of solution in oil. At discovery, all petroleum reservoir oils contain some natural gas in solution. Often the oil is saturated with gas when discovered; meaning that the oil is holding all the gas possible at the reservoir temperature and pressure and that it is at its bubble point. Occasionally, the oil will be under-saturated. In this case, as the pressure is lowered, the pressure at which the first gas begins to evolve from the oil is defined as the bubble point. |
| Dead Oil | Viscous oil that has little or no dissolved gas, will not flow through the rock, and cannot be recovered. |
| Drawdown | The flowing phase of a well test (followed by the build-up or shut-in phase). |
| Deep water | Deep water is defined as water depths greater than or equal to 1,000 ft (305 m), and ultra-deep water is defined as water depths greater than or equal to 5,000 ft (1,524 m). |
| Dynamic Positioning | A computer controlled system that keeps a drillship / vessel in the proper position and heading and not allow it to drift because of waves, currents, or wind. |
| DP Equipment Class | DP 1 (Equipment Class 1) has no redundancy. Loss of position may occur in the event of a single fault.<br>DP 2 (Equipment Class 2) has redundancy so that no single fault in an active system will cause the system to fail. DP 2 vessels have, as a minimum, two independent controller systems. Industry standards for 2011 require three controller systems (triplex). Class 2 DP units with equipment class 2 should be used during operations where loss of position could cause personnel injury, pollution or damage with great economic consequences.<br>DP 3 (Equipment Class 3) has to withstand fire or flood in any one compartment without the system failing. Loss of position should not occur from any single failure including a completely burnt fire sub-division or flooded watertight compartment. DP 3 vessels have, as a minimum, two independent controller systems with a backup system. Industry standards for 2011 require three controller systems (triplex). |

| Word / phrase | Definition |
|---|---|
| Fall-off Test | The measurement and analysis of pressure data taken after an injection well is shut-in. These data are often the easiest transient well test data to obtain. Wellhead pressure rises during injection, and if the well remains full of liquid after shut-in of an injector, the pressure can be measured at the surface, and bottom-hole pressures can be calculated by adding the pressure from the hydrostatic column to the wellhead pressure. |
| Field | Field is defined as an area consisting of a single reservoir or multiple reservoirs grouped on, or related to, the same general geologic structural feature and / or stratigraphic trapping condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers or both. |
| Horizontal Tree | A tree design for subsea applications configured with the valves and flow-control equipment offset to the side so that the tree provides vertical access from the tree cap to the wellbore for drilling or other downhole work. |
| Interference Test | Test of pressure interrelationships (interference) between wells serving the same formation.<br>The pressure variation with time recorded in observation wells resulting from changes in rates in production or injection wells. In commercially viable reservoirs, it usually takes considerable time for production at one well to measurably affect the pressure at an adjacent well. Consequently, interference testing has been uncommon because of the cost and the difficulty in maintaining fixed flow rates over an extended time period. With the increasing number of permanent gauge installations, interference testing may become more common than in the past.<br>Using interference testing, a larger reservoir area can be investigated than is possible with a single well test. Information about the inter-well connectivity, reservoir heterogeneities, and anisotropy (i.e., having properties that differ according to the direction of measurement) can be obtained. |
| Modular Formation Dynamics Tester | The modular formation dynamics tester (MDT) tool takes pressure measurements in real time and obtains fluid samples. |
| Nodal Analysis | The system analysis for determination of fluid production rate and pressure at a specified node. Nodal Analysis is performed on the principle of pressure continuity, that is, there is only one unique pressure value at a given node regardless of whether the pressure is evaluated from the performance of upstream equipment or downstream equipment. The performance curve (pressure-rate relation) of upstream equipment is called the “inflow” performance curve. The performance curve of downstream equipment is called the “outflow” performance curve. The intersection of the two performance curves defines the operating point, that is, the operating flow rate and pressure at a specified node.<br>Well performance analysis (i.e., Nodal Analysis) is based on the principle that one can independently characterize reservoir inflow and wellbore outflow as functions of flow rate. The single rate that balances the pressure losses in the inflow-outflow system defines well flow. |
| Permeability | Measures the ease in which a fluid flows through rock. The higher the permeability, the easier it is for the fluid to flow through the rock. Measured in Millidarcys (mD), values for permeability from 1 to 15 mD are poor; 15 mD to 50 mD are moderate; 50 mD to 250 mD are good; 250 mD to 1,000 mDare very good; with >1,000 mD being excellent. |

| Word / phrase | Definition |
|---|---|
| Play | Plays are defined generically as groups of geologically similar reservoirs and prospects within a common geographical area. Geological similarity is essential to ensure each group is homogenous. Geological similarity is defined primarily by stratigraphy (the reservoir formation) and the trapping mechanism. Secondary characteristics used to define plays include depositional environment, reservoir lithology, fluid type, and petroleum source. |
| Porosity | The percentage of pore volume or void space, or that volume within rock that can contain fluids. Effective porosity is the interconnected pore volume in a rock that contributes to fluid flow in a reservoir. |
| Pressure Transient Analysis | The analysis of pressure changes over time, especially those associated with small variations in the volume of fluid. In most well tests, a limited amount of fluid is allowed to flow from the formation being tested and the pressure at the formation monitored over time. Then, the well is closed (shut-in) and the pressure monitored while the fluid within the formation equilibrates. The analysis of these pressure changes can provide information on the size and shape of the formation as well as its ability to produce fluids.<br>Pressure drawndown analysis - The analysis of pressure-transient behavior observed while the well is flowing. Results are generally much less accurate than those from pressure buildup tests because the BHP fluctuates rapidly with even slight changes in the surface flow rate. Therefore, pressure buildup tests are much preferred, and analysis of drawdown test data is usually relegated to backup status unless the buildup data are flawed. |
| Shoe (guide shoe) | A tapered, often bullet-nosed piece of equipment often found on the bottom of a casing string. The device guides the casing toward the center of the hole and minimizes problems associated with hitting rock ledges or washouts in the wellbore as the casing is lowered into the well. The outer portions of the guide shoe are made from steel, generally matching the casing in size and threads, if not steel grade. The inside (including the taper) is generally made of cement or thermoplastic, since this material must be drilled out if the well is to be deepened beyond the casing point. It differs from a float shoe in that it lacks a check valve. |
| Skin | A dimensionless factor calculated to determine the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A positive skin value indicates some damage or influences that are impairing well productivity. A negative skin value indicates enhanced productivity, typically resulting from stimulation..For well testing, skin refers to the zone of reduced or enhanced permeability around a wellbore. |
| Trend | Used synonymously with the term *play* to describe an area in which hydrocarbons occur, such as the Wilcox trend of the Gulf Coast. |
| Vertical Trees | A vertical tree has swab valves vertically aligned with the wellbore. Because the valves are too small to drill through, the tree is installed after the well is drilled. |
| Viscosity | A property of fluids and slurries that indicate their resistance to flow, defined as the ratio of shear stress to shear rate.<br>Viscosity is the resistance to a change in form and is affected by temperature, pressure, the amount of gas in solution in a liquid, and the type and size of the molecules in the fluid. |
| Wireline | A cable that is commonly used to raise and lower equipment in a well. Wireline operations can be either non-electric such as slickline or swabbing, or electric such as logging (evaluating well properties using a sonde, i.e., electrical, acoustical, and radioactive properties of the formation and fluids). |

# 2 INTRODUCTION

## 2.1 DEEPWATER EXPLORATION – INDUSTRY CHALLENGES

Over the last 30 years, significant oil and gas reserves have been found by exploring deeper waters. The main challenges of deepwater exploration are risks associated with technology and cost. Many deepwater fields are geologically complex and require advanced technology, experienced personnel, and longer durations for operations. Some operators are reluctant to commission a development without extensive evaluation because in many cases, the predicated recoverable reserves and production were far less than initially forecast. For many operators, marginal deepwater fields with less than 100 MMBOE are considered cost prohibitive.

Deepwater well testing in the GoM, especially on discovery and appraisal wells, is virtually non-existent. The primary cause for the lack of testing is the high costs involved with mobilizing the conventional equipment with the appropriate capabilities to perform well tests. Deepwater projects require a combination of good reservoirs, advanced technology, and risk management to ensure economic success. Early reservoir appraisal to rapidly assess geological and reservoir attributes is important to minimize the developmental cost of deepwater fields and maximize production.

One of the major RPSEA strategic themes is the early appraisal of the reservoir with minimum drilling to reduce the risk associated with planning an economically feasible reservoir development. To accomplish this goal, well production testing is a necessity. Presenting practical deepwater low-cost well production testing solutions will provide incentives for operators to perform long-term well tests for discovery and appraisal wells, and for existing wells, help define reservoir characteristics, economics, and field management.

## 2.2 CURRENT METHODS OF WELL TESTING AND THEIR LIMITATIONS

Conventional well testing methods usually involve surface production of fluid or changing rate at the surface. For many exploration and appraisal scenarios, surface facilities are needed to store the produced fluids and handle the gas. Due to limited availability and cost for these storage facilities in deep waters, the fluid is discharged or flared. However, stringent environmental regulations may prohibit or limit discharge and / or flaring. The industry needs reliable, safe, cost-effective, and environmentally friendly test procedures, especially when conventional tests are prohibitively expensive, logistically not feasible, or no surface emissions are allowed.

Well tests have been widely used for several decades in the oil industry to estimate reservoir properties such as initial pressure, fluid type, permeability, and identify reservoir barriers / boundaries in the formation volume (near the wellbore) investigated by the test. Information collected during well testing usually consists of flow rates, pressure, temperature data, and fluid samples.

Conventional well test analysis provides data on the average properties of the reservoir in the vicinity of the well, but does not provide the overall reservoir characteristics and boundaries. One of the main reasons for this limitation is that traditional well test analysis handles transient pressure data collected from a single well over a short duration. For example, log and modular formation dynamic tester (MDT) data only provide information adjacent to the wellbore and seismic data cannot delineate the heterogeneity of the reservoir. Reliance on testing methods that may not provide accurate data or accurate assessment of the reservoir increases the financial risk to the industry.

Well testing in the GoM is done fairly routinely; however, most of the well testing occurs after well completion when the well is connected to a platform to start production. At this stage, if the testing shows the reservoir is not as economically feasible as the initial assessments anticipated, the calculated return-on-investment (ROI) may not be realized. Appraisal stage well testing is less common in the GoM since it currently requires a MODU, floating, production, storage, and offloading (FPSO) vessel, or tanker / barge to collect the produced fluids which increase the operating costs for operators.

There is no single method of testing and sampling that is fit for purpose under every circumstance. The selection of the test type, sequence, and duration must be balanced against operational risk, geology, environmental constraints, equipment, and the economic value derived from affecting early decisions on project appraisal or development.

## 2.3 IMPORTANCE OF WELL TESTING FOR EARLY RESERVOIR APPRAISAL

Well testing is predominantly performed only in the later development and production phases. The conventional short-duration well tests provide reservoir properties but the data is only applicable to the vicinity close to the wellbore. Conventional methods cannot characterize the reservoir or tell how the reservoir will behave over time. Economic success or failure can depend on proper reservoir characterization.

As with any business, the goal is to maximize the ROI. In the oil industry, the investment costs for exploration and production are massive. Answering questions about a reservoir's productivity and performance over time allows operators to make decisions on how much to invest, where to place wells, how to complete the wells, how to enhance and sustain production, what type of surface facilities will be needed over time, and how to minimize environmental, safety, and economic risks. Deeper wells and deeper waters have dramatically increased cost and risks.

Enhanced reservoir characterization during the early appraisal stage allows for more accurate decisions to justify the economic value of the reservoir and the costs associated with the design of production facilities that can exceed one billion dollars.

Early appraisal stage reservoir characterization uses well testing methods – short-term (Drill stem test [DST]), long-term (Extended well testing [EWT]), interference, and injection testing – coupled with static and dynamic modeling) to acquire data that allow the operator to:

- Estimate reservoir properties such as permeability, fractures, layers, geochemistry, etc.
- Estimate wellbore damage due to drilling and completion (skin).
- Estimate initial reservoir pressure.
- Assess produced fluid properties.
- Identify reservoir boundaries, compartmentalization, and heterogeneity.
- Estimate well flow potential based on different flow rates during the well test.
- Estimate reservoir production capacity and recovery potential.
- Forecast how the reservoir will behave over time.

There is no insurance against unpredictable reservoirs; however, using well testing during the early appraisal stage to determine the reservoir's characteristics provides valuable information resulting in better economic decisions.

# 3 PROJECT SCOPE AND OBJECTIVES

With RPSEA's Ultra Deepwater (UDW) program, one of the major strategic themes was to improve common practices for well tests in the deepwater GoM to provide better, more timely knowledge about reservoirs and reduce the risk associated with planning an economic deep water reservoir development. The *Early Reservoir Appraisal, Utilizing a Well Testing System* request for proposal (RFP) was issued and awarded to Nautilus International.

## 3.1 PROJECT OBJECTIVES

The project objective is to define appropriate cost-effective systems for testing deepwater reservoirs during the appraisal stage in a safe manner regarding personnel, the environment and equipment.

The high-level project goals from RPSEA stated that the proposed well testing options resulting from this project should reduce the risk of uncertainty, provide pertinent information to industry professionals, and that the proposed solutions must be cost effective.

The first aspect of this project was to design and perform detailed well test modeling for three reservoirs in the GoM. Details and results are discussed in Section 4. The goal of this modeling work was:

- Understand the well test duration for different well test types for different reservoirs.
- Estimate pressure, flow rate, and fluid production during the well test.

The second aspect of this project was to design surface and downhole systems that could accomplish the well testing and determine the feasibility of each system. Eight well testing systems to optimize deepwater well testing in GoM reservoirs were evaluated. This information is discussed in detail in Section 6 through Section 8.

The final project goal is to provide a roadmap for well testing options depending on the type of reservoir, type of subsea and surface equipment, and vessel(s) type. This project will:

- Provide management with a tool to value the application of early well testing in the deepwater wells.
- Provide engineers and geoscientists with a way to compare various well testing systems for deepwater testing applications.
- Provide a practical guide for deepwater well testing designs and operations.

An enormous amount of multi-discipline data has been collected and analyzed from numerous sources and industry professionals during this project. To better improve the decision-making capabilities for the oil industry, it became apparent that all this valuable data needed to be available in an easy to use manner. As part of the business plan, a future effort of the project is to provide a web-based modeling tool that can be used by industry professionals to determine the optimum well testing methods based on the type of reservoir, subsea and surface equipment, and vessel(s) criteria. Appendix A lists the ~150 megabytes of documents provided by subcontractors for this study that will be used as a basis of this computer-based modeling tool.

## 3.2 PROJECT ANATOMY

**Reservoirs:** For the three reservoir / plays in the GoM, selected by RPSEA Advisory Committee, the range of properties was assessed. These properties included permeability, porosity, fluid properties, pressures, temperatures, net pays, and saturations.

**Well test simulations:** Simulations (well test modeling) were performed for the range of properties for each reservoir. These simulations included short-term, long-term, interference, injection testing and nodal analysis. The results were converted into practical test designs that included:

- Sequence of drawdown / build up times.
- Production rates (gas – oil – water) and volumes.
- Pressure measurements (sensitivity).
- Effects of wellbore architecture (including depth, diameter, and deviation).

**Well test systems design:** Eight well test system designs were defined and incorporated:

- Environmental and safety considerations.
- Major components.
- Layout of testing systems (including drawings).
- Dynamic positioning (DP) requirements for GoM.
- Riser system design.
- Control of well tests and equipments.
- Flow assurance.
- Downhole operational considerations.

**Operational considerations:** For each of the eight systems, operational considerations included the overall operating, maintenance and contingency plans. Practical considerations for deck handling, deployment of the riser and downhole operations were identified. Cost estimates and technical readiness for each system were evaluated.

**Available Vessels in the GoM for Well Testing**: A detailed spreadsheet of available vessels was compiled with specifications for current functional descriptions, length, storage capacity, riser handling, cranes, ROV, derrick, DP capability, and accommodations. The spreadsheet is listed in Appendix A. Section 9 provides an overview of some of the vessels in the GoM capable of well testing.

## 3.3 PROJECT TEAM

A team of highly competent industry professionals and subject matter experts have been involved throughout this project. The project team is shown in Figure 1 and the subcontractor areas of expertise are detailed in Table 2.

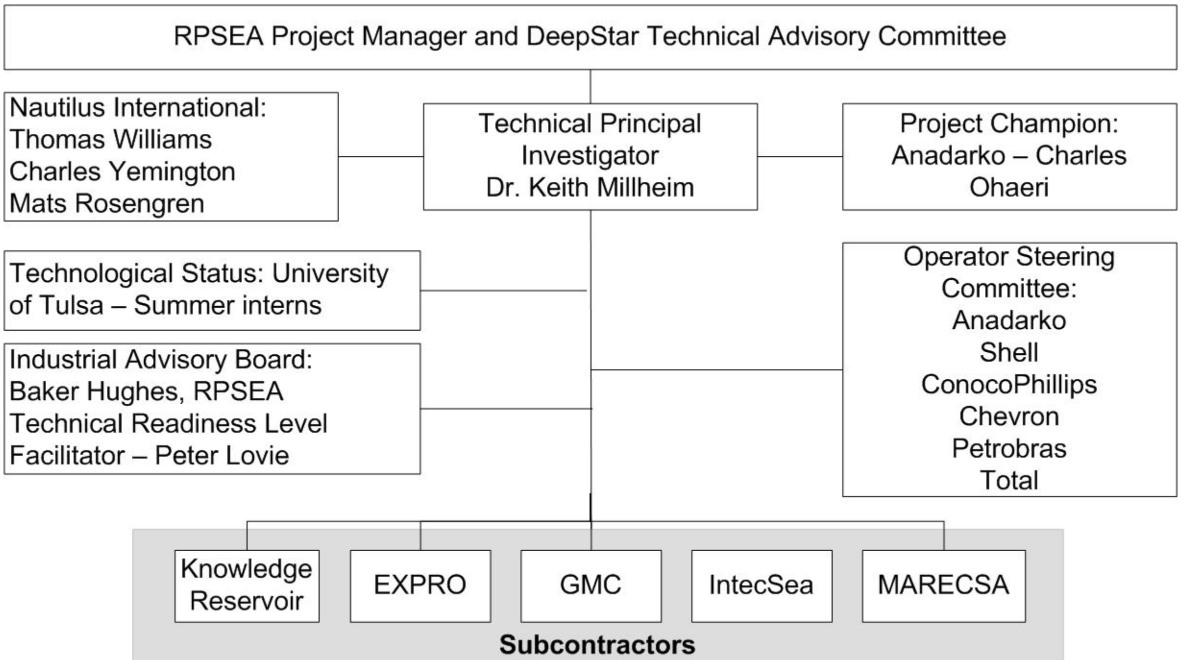



**Figure 1**
**Project 2501 Team Members**

| Table 2<br>Subcontractor Area of Expertise | |
|---|---|
| **Subcontractor** | **Area of Expertise** |
| Knowledge Reservoir | Reservoir properties and simulations. |
| EXPRO | Surface testing systems and safety; deck layout and facility requirements. Downhole and subsea equipment. Analysis of three typical vessels used for well testing. |
| GMC | Marine testing systems (subsea) including operations, control philosophy, and emergency safety of each system. Available vessels in the GoM |
| Intecsea | Well tieback riser design and analysis. Detailed design and analysis of the self standing riser (SSR). |
| MARECSA | Non-MODU vessel classification and descriptions. Provide description, operations, safety of a well testing service vessel (WTSV) with DP2 classification FPSO. |
| **Note**: A complete list of all reports submitted by the subcontractors is in Appendix A. | |

# 4 RESERVOIR WELL TESTING

## 4.1 RESERVOIR OVERVIEW

Three different deepwater GoM reservoir plays were selected for well test modeling – Middle Miocene, Lower Tertiary Paleocene, and Lower Tertiary Eocene reservoirs. The reservoirs represent a wide range of reservoir and fluid properties and are the most active reservoirs in terms of exploration and production.

Upper tertiary trend consist of both Pliocene and Miocene reservoirs and hold approximately 99% of proven GoM reserves. Several significant discoveries have been made in the upper tertiary sands over the last few years, including Mad Dog, Neptune, and Thunder Horse. The fluid properties in the Middle Miocene are the best known of all three reservoirs due to the extensive exploration activities and a long production record.

The lower tertiary trend consists of Oligocene, Eocene, and Paleocene reservoirs. Several big Paleocene sand discoveries have been announced, such as Chinook, Jack, St. Malo, and Cascade. There are only a few fields available in the Paleocene trend to provide information on reservoir and fluid properties which makes this reservoir the least characterized.

Although the Eocene reservoir is part of the Lower Tertiary trend, this reservoir is much shallower in terms and depth below the mudline and reservoir properties are very different from deeper Paleocene sands. The Shell Perdido project is the most recent field to produce from the Eocene sands. Information gathered from Shell Perdido project and other development fields (Great White, Trident, and Silver Tip) were used to characterize this reservoir.

Figure 2 shows Middle Miocene reservoir. Figure 3 shows the Paleocene and Eocene reservoirs in the Lower Tertiary Trend.

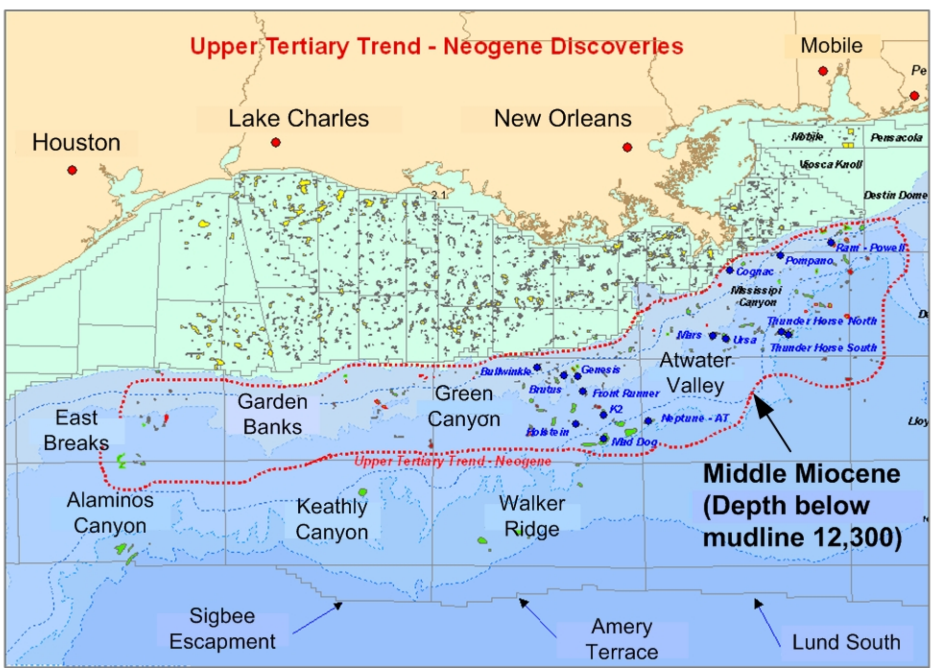



**Figure 2**
**Middle Miocene Reservoir in the Upper Tertiary Trend**

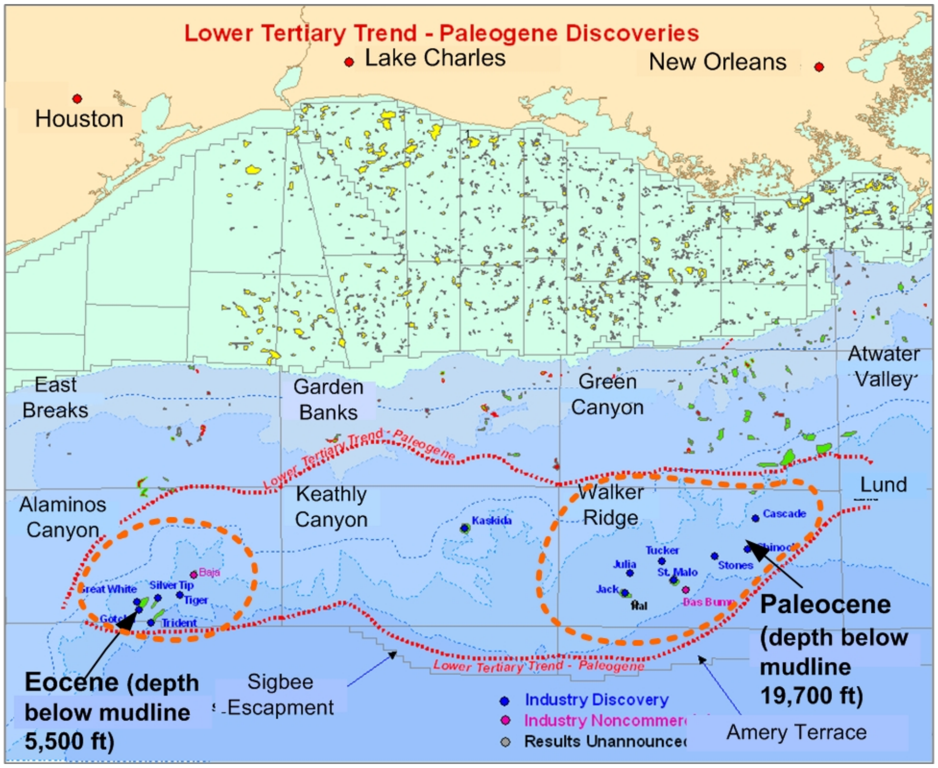



**Figure 3**
**Paleocene and Eocene Reservoirs in the Lower Tertiary Trend**

Figure 4 provides some deepwater stratigraphic structures and the estimated billion barrels of oil equivalent (BBOE) in each system by reservoir age.

| Time (mya) | System | Subsystem | Series | Total Proved Reserves | Discovered BOE All Water Depths | Discovered BOE Water Depths >1,000 ft |
|---|---|---|---|---|---|---|
| | Quaternary | | Pleistocene | 98.9% (52.3 BBOE) | 94.2% (58.5 BBOE) | 84.9% (15.6 BBOE) |
| 1.77 | Tertiary | Upper | Pliocene | | | |
| | | | Miocene | | | |
| 23.80 | | Lower | Oligocene | 0.4% (0.2 BBOE) | 4.5% (2.8 BBOE) | 15.1% (2.8 BBOE) |
| | | | Eocene | | | |
| | | | Paleocene | | | |
| 65.00 | Cretaceous | Upper | | 0.7% (0.4 BBOE) | 1.3% (0.8 BBOE) | —— |
| | | Lower | | | | |
| 144.20 | Jurassic | Upper | | | | |
| 164.40 | | Middle | | | | |

**Figure 4:**
**Deep Water Stratigraphic Structures**

The three reservoir types were selected because of the wide range of reservoir and fluid properties. The unique characteristics of each reservoir will provide greater insight into well testing for deepwater GoM fields. The goal is to incorporate this information into a web-based computer modeling tool (future effort resulting from this project) that will provide operators greater decision making capabilities on which well test design to use.

## 4.2 WELL TESTING METHODOLOGY

### Typical well test

During well testing, pressure gauges are placed near the bottom of the well to capture the data. A typical well test has a flowing phase (drawdown) followed by a build-up (shut-in) phase.

During drawdown, fluid is allowed to flow from the formation and the bottom-hole pressure (BHP) and flow rate is monitored over time. Then, during shut-in, the well is closed and the BHP monitored while the fluid within the formation equilibrates. Several drawdown and build-up phases are carried out as needed. The analysis of the BHP changes, known as pressure transient analysis (PTA), provides information on the size and shape of the formation as well as its ability to produce fluids.

The resulting data is analyzed through computer modeling using methods such as the log-log plot (also called derivative plot), semi-log plot, Horner plot, and other specialized plots to evaluate the reservoir properties. Most of the models used for PTA assume the reservoir is homogeneous, meaning the rock properties do not change with location within the reservoir.

### Types of well testing

Conducting different kinds of well tests provides more useful information depending on the field development phase and complexity of the reservoir

*Short-term test or Drill Stem test (DST)* – This is usually a quick test done using a 3-1/2 in tubing to the guide shoe with a drill pipe string in the hole. A short-term test is conducted in a well to collect basic reservoir and fluid properties such as permeability, pressure, and skin (i.e., wellbore damage). The test duration is short, but long enough to achieve radial flow so that the desired properties can be calculated from the pressure data.

*Long-term test or extended well test (EWT)* – This test is important for both the exploration and appraisal phase to provide information about reservoir extent and continuity. The objectives are to find the reservoir boundaries and understand the long-term flow rates to design test facilities and perform economic analysis of the field. Reservoir compartmentalization is one of the most significant factors to decide if field development is economic. A long-term test is the best tool to provide this information.

*Nodal Analysis* – For both short-term and long-term test, nodal analysis is used to estimate the pressure and temperature at the wellhead (mudline) and separator (sea level) at various flow rates and other reservoir parameters (e.g., downhole pressure). Nodal analysis was performed using Petroleum Experts, Inc. software, Prosper.

*Interference test* – This test is used to investigate communication between two wells and determine reservoir properties. In a traditional interference test, the first well is an active well which is producing (or injecting) while the second well is an observation well monitoring BHP in response to changes in rate and pressure from the first (active) well. Interference test is a very common method to understand reservoir continuity.

For high permeability reservoirs like the Middle Miocene, interference testing is useful as a pressure pulse can reach an observation well far from an active well. For a low permeability reservoir like the Paleocene, an interference test may not be useful because the pressure pulse cannot travel far enough to reach the observation well. Nonetheless, due to the simplicity of the process and low cost, interference tests are frequently useful in the GoM.

*Injection well test* – With this test, fluid is injected into reservoir from the wellhead and a full column of fluid is maintained in the wellbore. Once injection is stopped, a fall-off test measures the pressure decline as a function of time. In many reservoirs, the formation pressure is high enough to maintain a full column of fluid in the reservoir and the pressure can be monitored at the surface. The BHP is calculated by adding the weight of the fluid column to the surface pressure.

As a result of a meeting with the RPSEA Technical Committee, injection testing was added to the original well testing methods stated in the original RFP. Well test designs were incorporated for both short-term and long-term tests using the injection method for the Middle Miocene reservoirs.

Since the fluid is injected into the reservoir, the test has several advantages over the other well tests:

- No reservoir fluid (i.e., live oil) is produced at the surface. The injected fluid is either dead oil or water but ideally should mimic the reservoir properties.
- Safety risks are reduced regardless of reservoir type.
- Since there are no produced fluids at the surface, there is also no gas. For high Gas-oil-ratio (GOR) reservoirs like Eocene, this substantially reduces the environmental impact.
- Surface facilities are simplified with no produced fluids.
- Reservoir pressure and fluid pressure at the wellbore do not go below the bubble point which eliminates any issues with two-phase flow.

One of the primary concerns with injection testing is harming the reservoir by injecting fluids into it that have very different properties from the reservoir. With a green (virgin) field, fluid properties are not known. Collecting and analyzing a sample, using a sampling tool (i.e., MDT) during wireline logging, would mitigate this risk beforehand.

## 4.3 WELL TESTING RESERVOIR PARAMETERS

To conduct well testing simulations for the three reservoirs, average parameters including porosity, permeability, pressure, temperature, depths, oil viscosity, and GOR needed to be identified or assumed. This data was gathered by Knowledge Reservoir, Inc. using their proprietary software (ReservoirKB), and other publicly available sources such as Offshore Technology Conference (OTC) and Society of Petroleum Engineers (SPE) papers. The average parameters for each reservoir were used to establish the well test design.

A summary of some of the parameters for the three reservoirs are shown in Table 3.

**Table 3**
**Reservoir Parameters used for Well Testing**

| Parameter | Middle Miocene | Paleocene | Eocene |
|---|---|---|---|
| Net Oil Thickness | 35 ft | 210 ft | 75 ft |
| Porosity | 28% | 17% | 28% |
| Water Saturation (Sw) | 25% | 30% | 25% |
| Permeability | 500 mD | 16 mD | 100 mD |
| Rock Compression | 12 microsips | 3 microsips | 3 microsips |
| Original Oil in Place (OOIP) | 100 MMstb | 850 MMstb | 700 MMstb |

| Table 3<br>Reservoir Parameters used for Well Testing | | | |
|---|---|---|---|
| **Parameter** | **Middle Miocene** | **Paleocene** | **Eocene** |
| Area | 1,800 acres | 5,000 acres | 7,500 acres |
| Water Depth | 4,200 ft | 7,800 ft | 8,500 ft |
| Subsea Depth | 16,500 ft | 27,500 ft | 14,000 ft |
| Depth Below Mudline | 12,300 ft | 19,700 ft | 5,500 ft |
| Initial Reservoir Pressure | 11,000 psi | 19,500 psi | 7,000 psi |
| Reservoir Temperature | 186ºF | 230ºF | 140ºF |
| GOR | 1,000 scf/stb | 300 scf/stb | 1,800 scf/stb |
| Saturation Pressure | 5,000 psia | 1,200 psia | 5,000 psia |
| Oil Viscosity | 1.5 cp | 3.5 cp | 0.45 cp |
| Oil Rate (Production) | 6,000 stb/d | 6,000 stb/d (jack test) | 6,000 stb/d |

## 4.4 WELL TESTING RESULTS FOR THE THREE RESERVOIRS.

Well test design and simulation provided useful information about the feasibility and importance of conventional production tests and injection tests. The three reservoirs selected for testing, Middle Miocene, Eocene, and Paleocene, represent a wide range of reservoir and fluid properties. Their unique characteristics provided valuable insight about deepwater well testing in the GoM. The results from the production well test simulations for the three reservoirs are shown in Table 4. The results from the injection tests are shown in Table 5.

| Table 4<br>Production Well Test Results | | | | |
|---|---|---|---|---|
| **Parameter** | **Units** | **Middle Miocene** | **Eocene** | **Paleocene** |
| **Short Term Test Design** | | | | |
| Duration | hr | 14 | 16 | 24 |
| Oil Rate | STB/D | 2,000 | 1,000 to 3,000 | 1,000 to 3,000 |
| Cum Oil | MSTB | 0.5 | 0.75 | 0.9 |
| Cum Gas | MMSCF | 0.5 | 1.35 | 0.25 |
| **Long Term Test Design** | | | | |
| Total Test Duration | days | 28 | 180 | 140 |
| Oil Rate | STB/D | 2,000 to 4,000 | 1,000 to 3,000 | 1,000 to 3,000 |
| Cum Oil | MSTB | 129 | 167 | 174 |
| Cum Gas | MMSCF | 129 | 300 | 52 |
| **Nodal Analysis** | | | | |
| Reservoir Pressure | psia | 11,000 | 7,000 | 19,500 |
| Bottom-hole Flowing Pressure | psia | 10,200 | 6,200 | 13,400 |

**Table 4**
**Production Well Test Results**

| Parameter | Units | Middle Miocene | Eocene | Paleocene |
|---|---|---|---|---|
| Flowing Mudline Pressure | psia | 6,500 | 3,500 to 5,000 | 1,000 to 6,000 |
| Flowing Surface Pressure | psia | 5,000 | 1,300 to 2,700 | Negative -3,200 |
| **Interference Test Design** | | | | |
| Flow Duration | day | 7 | 25 | 90 |
| Build-up / Monitor Duration | day | 21 | 25 | 90 |
| Oil Rate | STB/D | 2,000 to 4,000 | 2,500 | 2,500 |
| Gas Rate | MMscf/d | 0.6-1.2 | 4.5 | 0.75 |
| Cum Oil | MSTB | 32 | 62.5 | 225 |
| Cum Gas | MMSCF | 32 | 112.5 | 67.5 |

**Table 5**
**Injection Well Testing Results**

| Parameter | Units | Middle Miocene | Eocene | Paleocene |
|---|---|---|---|---|
| **Short Term Test Design** | | | | |
| Duration | hr | 6 | 6 | 24 |
| Oil Rate | STB/D | 2,000 | 2,000 | 2,000 |
| Cum Oil | MSTB | 0.25 | 0.25 | 1 |
| Cum Gas | MMSCF | 0 | 0 | 0 |
| **Long Term Test Design** | | | | |
| Total Test Duration | day | 28 | 150 | 120 |
| Oil Rate | STB/D | 2,000 | 2,000 | 1,000 |
| Cum Oil | MSTB | 28 | 150 | 120 |
| Cum Gas | MMSCF | 0 | 0 | 0 |
| **Nodal Analysis** | | | | |
| Reservoir Pressure | psia | 11,000 | 7,000 | 19,500 |
| Bottom-hole Flowing Pressure | psia | 11,350 | 7,330 | 21,500 |
| Flowing Mudline Pressure | psia | 7,600 | 5,900 | 14,300 |
| Flowing Surface Pressure | psia | 6,300 | 3,800 | 11,700 |

## 4.5 SUMMARY OF WELL TEST RESULTS

Middle Miocene reservoir properties are the most favorable for well testing. The long-term test duration for the Middle Miocene was significantly less that the other reservoirs because of the high permeability and low viscosity. Along with high permeability, low viscosity, and shallow water depths, the Middle Miocene has the highest oil production rate. The low pressure drawdown (flowing phase) keeps the reservoir pressure above the bubble point. This keeps the gas saturated in the oil ensuring a single-phase flow at the sandface.

Lower Tertiary Paleocene reservoir well testing provides numerous challenges. The well test simulations for this reservoir are difficult due to limited data on reservoir and fluid properties. The reservoir is very deep and has a high degree of compartmentalization. Paleocene permeability is very low and the fluid viscosity is high. All these factors increase test duration times and may limit the type of test that can be performed based on time, and cost factors. The results from this project show that the Paleocene reservoir has the most unfavorable well testing conditions.

The Eocene reservoir is part of the Lower Tertiary Trend but the reservoir depth is shallower and the formation permeability is higher than the Paleocene reservoir. Well testing accuracy is also limited by available data on reservoir and fluid properties. Compared to the other two reservoirs, the Eocene reservoir has the highest GOR and the greatest water depth. The high GOR produces more gas during well testing and may raise environmental and regulatory concerns. The extreme water depth also suggests problems with getting the production fluids to the surface.

At the beginning of this modeling work, the maximum flow rate for the drawdown phase for all three reservoirs was estimated to be 6,000 STB/D. However, the short-term well test simulations showed that the same results could be achieved using considerably lower flow rates (1,000 STB/D to 3,000 STB/D). The lower flow rates result in less total oil and gas produced to the surface. This provides numerous options for operators in determining the surface facilities needed to perform well testing.

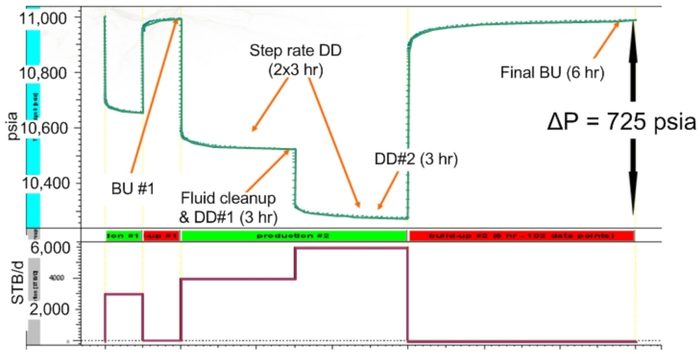
The injection test results were very encouraging in terms of fluid volume and test duration. The results mimic those from the conventional production tests. There are numerous benefits for operators in the GoM with the injection test, including eliminating environmental concerns and simplifying surface facilities needed for testing.

Prior to implementing injection testing, a detailed analysis on the injection fluid properties, method and sweep efficiency should be conducted.

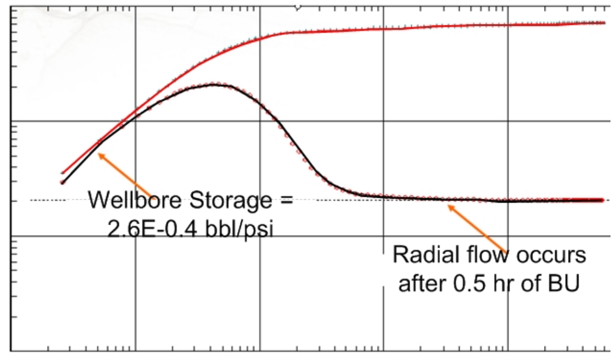
Table 6 shows production well test simulation pressure / rate / time plots and log log plots for each reservoir. Table 7 shows the injection well test simulation results for the Middle Miocene and compares it to the production well test simulation plots for the Middle Miocene

## Table 6
## Production Test Simulation Results for the Three Reservoirs

**Middle Miocene**

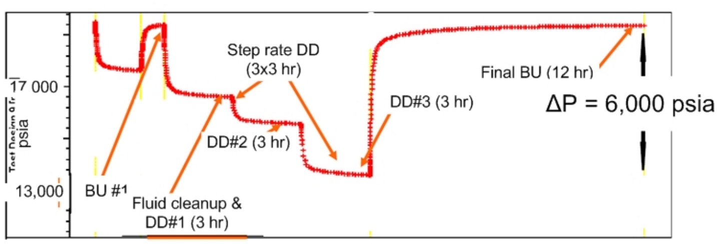



Pressure (psia) and Rate (STB/d) vs. Time (hr)

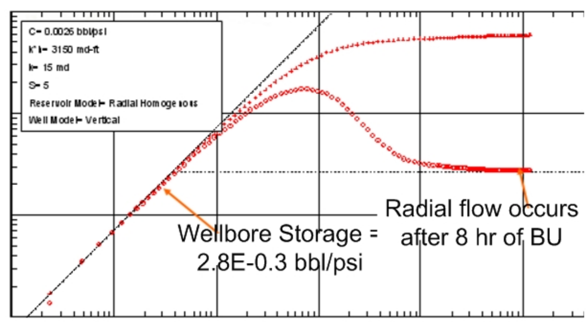



Log-Log Plot: dp and dp' (psi) vs. dt (hr)

**Lower Tertiary - Paleocene**

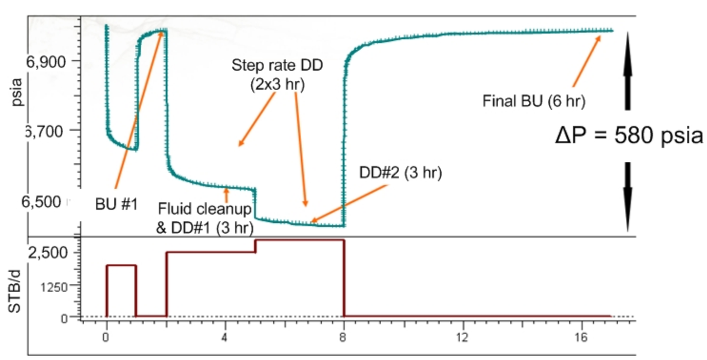



Pressure (psia) vs. Time (hr)

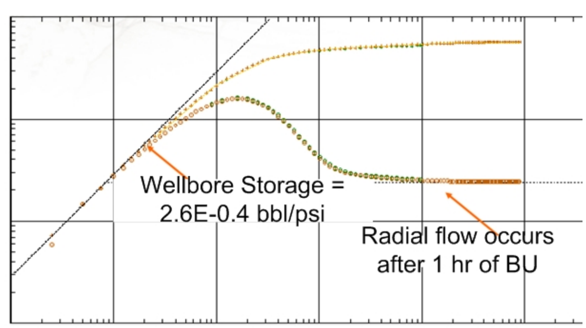



Log-Log Plot: dp and dp' (psi) vs. dt (hr)

**Lower Tertiary - Eocene**



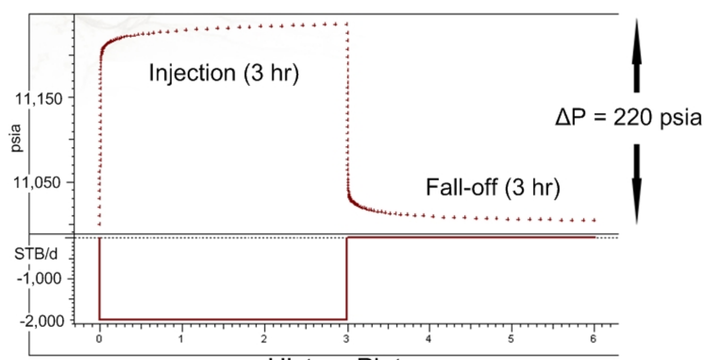

Pressure (psia) and Rate (STB/d) vs. Time (hr)



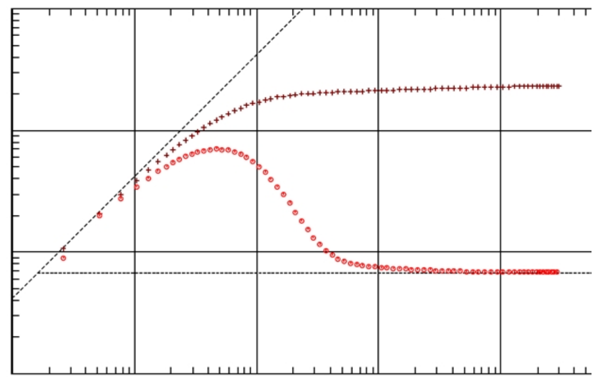

Log-Log Plot: dp and dp' (psi) vs. dt (hr)

## Table 7
## Injection Test Results for Middle Miocene and Comparison to the Production Tests

**Injection Test Results – Middle Miocene**

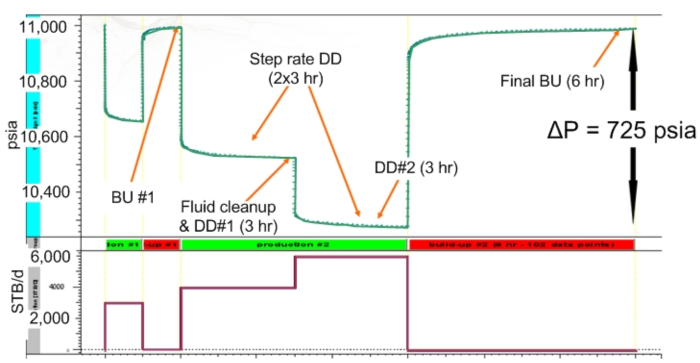



History Plot
Pressure (psia) and Rate (STB/d) vs. Time (hr)

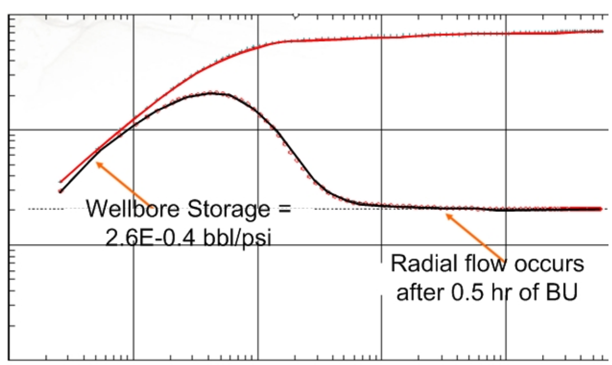


Log-Log Plot: dp and dp' (psi) vs. dt (hr)

**Middle Miocene Production Test Results**




Pressure (psia) and Rate (STB/d) vs. Time (hr)




Log-Log Plot: dp and dp' (psi) vs. dt (hr)

dp = Delta (Δ) Pressure

dt = Delta (Δ) Time

# 5 FROM RESERVOIR ANALYSIS TO WELL TEST SYSTEM DESIGN AND FEASIBILITY

By design, the project study was divided into two distinct sections: The first section is reservoir oriented focusing on what type of reservoir should be tested, how it should be tested, and what type of possible results would come from certain production or injection rates (i.e., pressure responses). The second section addresses the design and operational issues necessary to give the Reservoir Engineer the results to accomplish the pressure testing analysis. Task 5.0 focused on the reservoir part, whereas, Task 6.0 addresses all the design and operational issues.

Deepwater well testing is multi-disciplinary, requiring expertise in completions, subsea equipment, riser systems, surface production units, and most importantly, all the safety concerns associated with the well testing. It was necessary to engage experts in each field who could address all these multi-disciplinary design and operational variations to complete Task 6.0. What also complicated the scope of Task 6.0 are the eight possible testing systems that could be considered.

Basically, these eight testing systems cover the following situations:

1. The well only has a wellhead and no production tree, or the well has either a vertical or horizontal tree, but is not connected to any fixed production facility.
2. The riser will either connect directly to the production vessel and the wellhead or production tree, or the riser will be free standing with a flexible pipe to the production facility.
3. The final consideration is the type of facility / vessel to handle the production fluids, separate the oil, gas, water, and sand, and then store the fluids and treat the gas. These vessels can be the MODU with production facilities, an FPSO, or an FPU and some type of storage vessel.

Task 6.0 does not support any best way to do deepwater well testing. The study results gives the Engineer all the options, taking in the circumstances of safety, logistics, economics, and actual well and reservoir conditions. Some combination will dictate the best well testing design and operational procedures for each unique situation.

## 5.1 WEB-BASED COMPUTER MODEL TO EVALUATE VARIOUS WELL TESTING OPTIONS

One of the project's future deliverables to provide a computer-based modeling tool that will serve as a decision tree matrix to assist industry professionals in selecting the appropriate well test design system. The results of the reservoir simulations clearly show that certain deepwater well tests can be optimized to determine the reservoir characteristics. Better data gathered during early reservoir appraisal well testing only leads to better estimations and decisions on the economic feasibility and longevity of the reservoir production capacity. Figure 5 illustrates how this future computer-based model will function. Funding for this effort has not yet been identified. Appendix C illustrates the template for this tool.

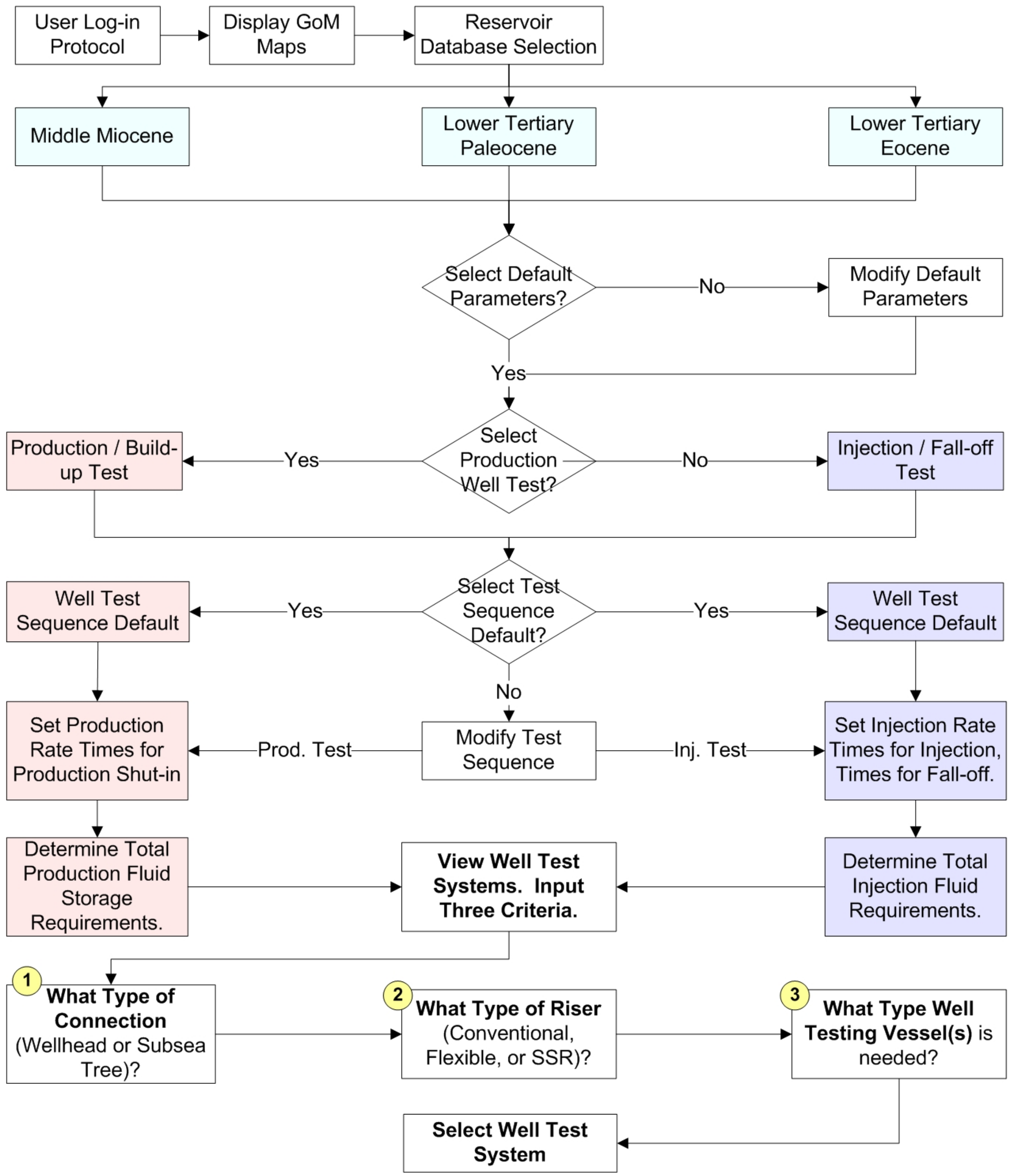



**Figure 5**
**Future Computer-based Modeling Tool High Level Template**

# 6 WELL TESTING SYSTEMS FOR SUBSEA WELLS

## 6.1 WELL TESTING SYSTEMS OVERVIEW

Three criteria were used to develop the well testing systems; subsea connection type, riser type, and vessel type. From these three criteria shown in Figure 6, eight well test systems were designed and the operational and safety feasibility of each system was assessed.

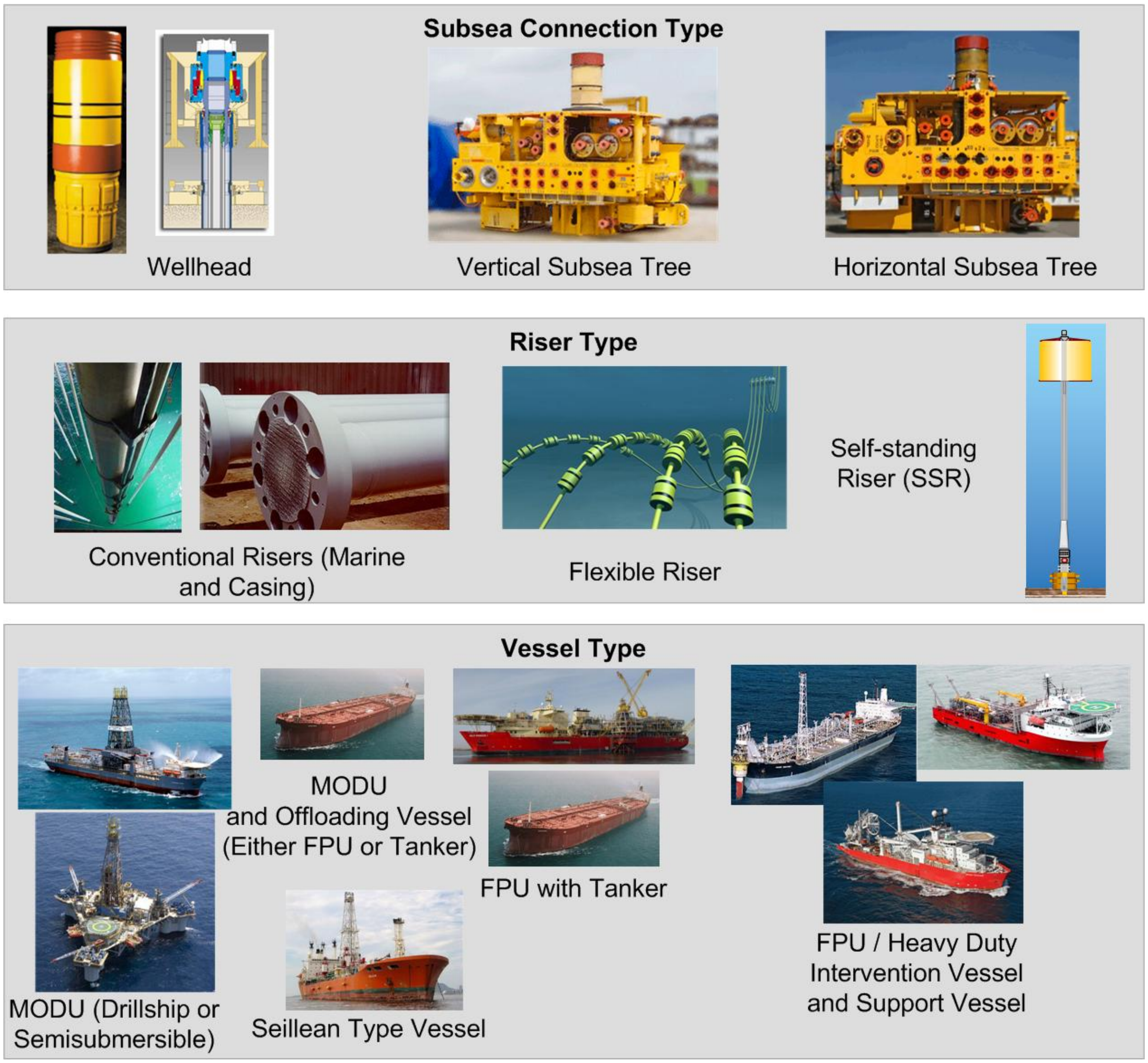



**Figure 6**
**Three Criteria Used to Develop the Eight Well Test Systems**

## 6.2 TECHNOLOGY READINESS LEVEL ASSESSMENT

The Technology Readiness Level (TRL) assessment provides the maturity status of the major components comprising each well test system. The TRL identified where further technical development is required for each of the eight well test systems to enable its operation or to improve the projected performance of each well test system.

The assessment was conducted through a workshop. Fourteen subject matter experts, from various disciplines, who have been involved throughout this project participated in the workshop. The workshop was moderated by an independent party for maximum objectivity and effectiveness. The TRL process involves detailed discussion on the technology development status of all the components for each well test system. The participants' then vote on each system and components in an open forum using a TRL scale established for technologies in the petroleum industry. Once the main voting process was over, a second discussion along with voting was held to assess the interest and recommendations for future actions.

The average rating scale (definitions for each listed in Appendix B) for each of the eight systems is shown below in Table 8. The scale is from TRL 1 through TRL 7, where seven is the highest level meaning the technology is in production and has successfully operated with acceptable performance and reliability for >10% of its specified life.

**Table 8**
**Summary of Average TRL Ratings**

| System | Description | TRL Avg. Rating |
|---|---|---|
| 1 | Standard deep water MODU, using a marine drilling riser, connects directly to the wellhead, uses a subsea BOP, and production facilities and oil storage are on the MODU (usually used for short term tests). | 7.00 |
| 2 | Standard deep water MODU, using a casing drilling riser, connects directly to a wellhead, uses a surface BOP, and production facilities and oil storage are on the MODU. | 6.64 |
| 3a | Utilizes System 1 with a subsea BOP, but production facilities and oil storage are not on the MODU so an offloading vessel is required. | 6.93 |
| 3b | Utilizes System 2 with a surface BOP, but production facilities and oil storage are not on the MODU and so an offloading vessel is required. | 4.64 |
| 4 | This is a Seillean type, FPSO, or Floating, drilling, production, storage, and offloading (FDPSO) vessel system where the vessel has the ability to run a rigid production riser, connect and disconnect to subsea production tree, treat the produced fluids and store the oil or transfer the oil to another storage vessel. | 6.79 |
| 5 | This system uses a FPU or FPSO with a flexible riser that connects to a subsea tree or pipeline end termination (PLET). Depending on depth, an installation vessel may be required to deploy and retrieve the flexible pipe. The FPU or FPSO vessels can either processes and store the fluids, or transfers the fluids to another offloading vessel. | 5.29 |
| 6 | This system uses a well intervention vessel (WIV) or MODU to connect to the subsea production tree via a rigid production riser. The WIV or MODU can intervene through the production tree to the well (i.e., re-complete, pull tubing, and run special downhole equipment). | 7.00 |

**Table 8**
**Summary of Average TRL Ratings**

| System | Description | TRL Avg. Rating |
|---|---|---|
| 7 | This testing system can use various vessels (WIV, FPSO, MODU, etc.) and uses a flexible riser to connect to the buoyancy module of a self standing riser (SSR) that is connected to subsea tree. This system can use a single barrier riser, or dual barrier riser via a tie-back liner in the riser. The SSR is installed by a separate vessel. | 4.79 |
| 8 | This system is very similar to System 7, except that the SSR is connected to sea floor with a suction anchor because the subsea tree will not support the SSR. | 6.93 |

All participants (regardless of company or field of expertise) had very similar opinions on each system and the votes reflected this general consensus. In summary, with the exception of systems 3b, 5 and 7, all other systems were at the top end of the scale (i.e., TRL 6 to TRL 7).

For future recommendations, all the participants believed further investigation to utilize injection testing were definitely worthwhile and should be pursued.

## 6.3 EIGHT WELL TESTING SYSTEMS DESCRIPTION

The following are the eight well test systems and a brief description of the vessel(s), well testing, risers, safety, emergency disconnect, and handling of fluids for each system. For additional clarification, ESD and EDS in this report have the following definitions:

- ESD – Emergency shutdown (shut-in the well, but do not disconnect)
- EDS – Emergency disconnect sequence (shut-in the well and disconnect)

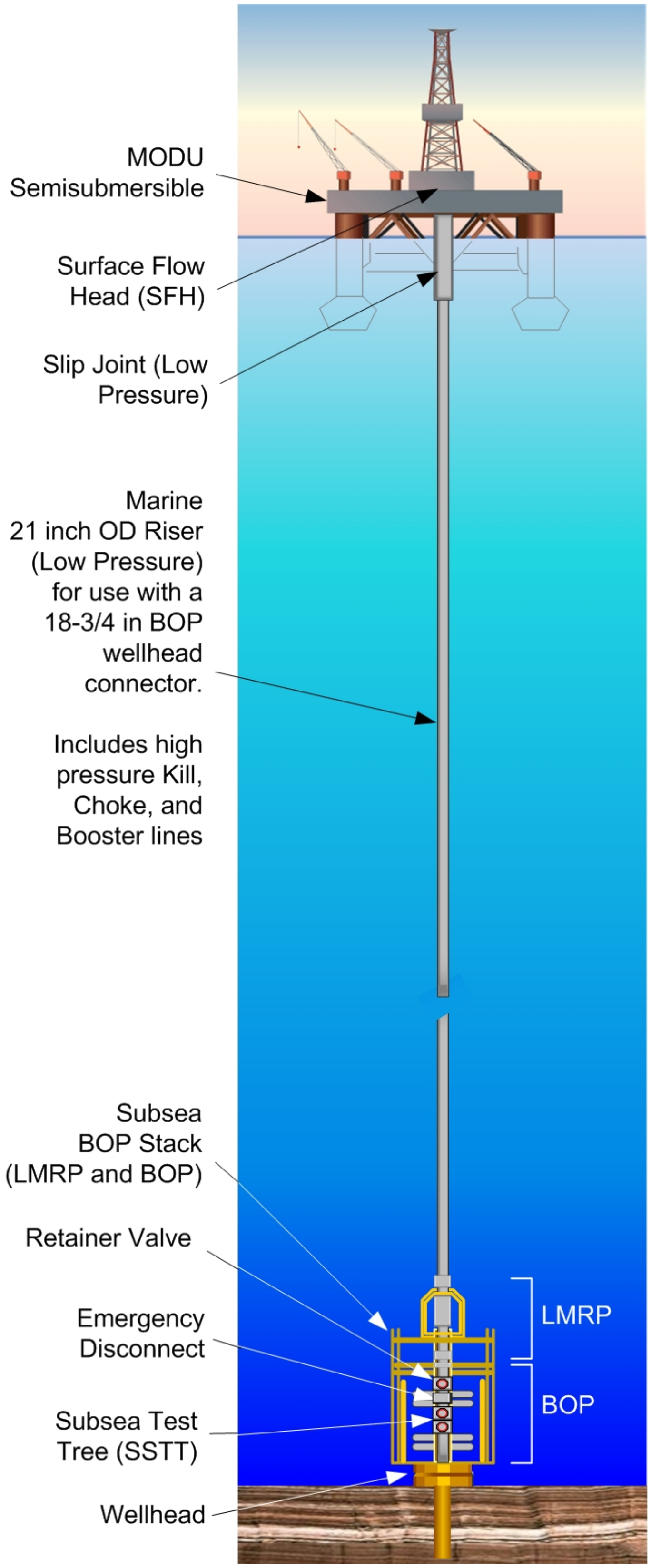



**Figure 7: Well Test System 1**

**Vessel**

- Standard MODU with 4th to 6th generation drilling equipment.
- Subsea BOP stack.
- DP capable.
- Limited deck space and storage capability.
- Control of the BOP via MODU's multiplex subsea control system (MUX). A second acoustic control system is preferable (and required in certain countries).

**Well testing**

- Proven methodology for DST.
- Limited storage determines test duration for EWT.

**Riser**

- Conventional 21 in OD low pressure marine riser with a standard subsea 18-3/4 in BOP wellhead connector.
- Riser contains high pressure rigid lines for kill, choke, and booster lines; and two hydraulic lines.
- Procedures are in place to prevent any damage to the umbilicals due to environmental conditions for pitch, roll, and heave motion of the vessel.

**Safety**

- Established method of control.
- SFH can isolate the well on the surface.
- High set well access valve (WAV) ~150 ft below rotary table can also isolate the well.
- Subsea Test Tree (SSTT) can shut-in the well within the BOP stack and disconnect without killing the well. SSTT disconnect will seal the landing string and prevent the fluids from leaking.
- Standard BOP operations.

**Emergency Disconnect**

- Proven emergency disconnect sequence (EDS) operational procedures, both automated and manual via ROV.

**Handling of Fluids**

- Limited storage capabilities for hydrocarbons.
- Equipped with flare booms.

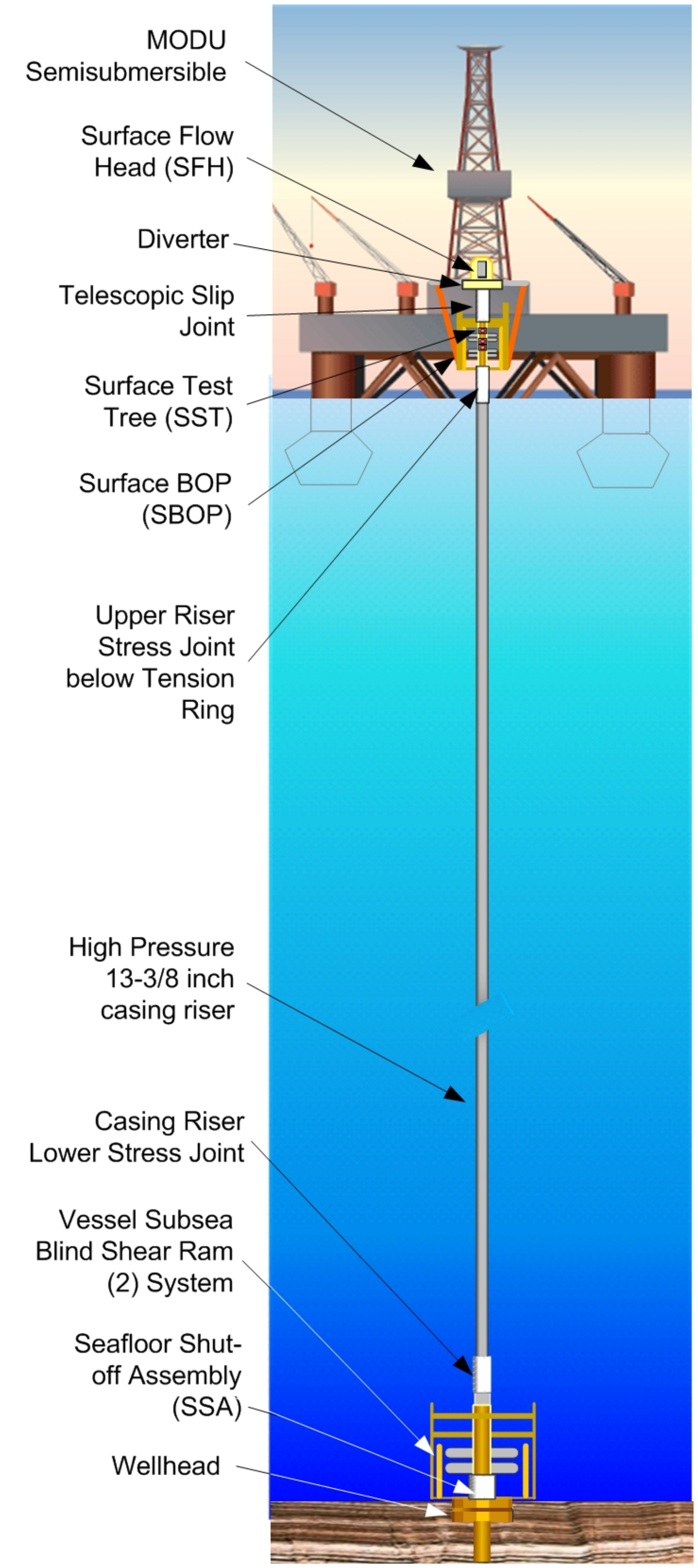



**Figure 8: Well Test System 2**

**Vessel**

- Standard MODU with 4th – 6th generation drilling equipment.
- Surface BOP stack – new technology for DST and EWT in GoM.
- DP capable.
- Limited deck space and storage capability.
- Control of SBOP is via MODU's MUX system.
- The SSA is controlled via an acoustic control system. This acoustic system serves as the primary control. The MUX system is the secondary control system.
- Certification may limit vessel availability.

**Well Testing**

- Limited storage determines test duration.

**Riser**

- Casing 13-3/8 in riser reduces environmental loads and top tension compared to a marine riser.
- Casing riser takes less time to install than marine riser with subsea BOP.
- An EDS for riser disconnect is located on top of the SSA.
- Casing riser connects SSA to the tension ring and surface BOP

**Safety**

- Surface BOP.
- MUX umbilical clamped onto the casing riser for subsea control of the two shear rams, SSA, and riser disconnect from the SSA.
- The SSA can isolate the wellbore subsea.
- The SSA can shear the DST string with vessel initiated EDS and drive-off. This would require a fishing job to retrieve the DST string once the vessel reconnects to the SSA.
- A retainer valve installed above the SSA will prevent hydrocarbon spillage with unlatch.

**Emergency Disconnect**

- EDS and drive-off procedures are in place.
- There is no SSTT, so after an EDS 1, well control is with the vessel and not subsea.

**Handling of Fluids**

- Limited storage for hydrocarbons.
- Flare booms available.

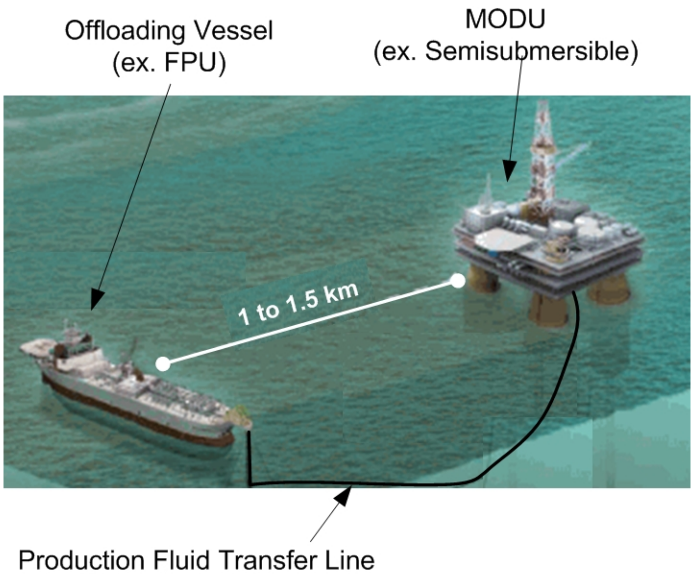



**Figure 9: Well Test System 3**

**Vessel**

- System 3 utilizes either System 1 or System 2.
- System 3 is used when additional storage requirements are needed for System 1 and 2. An offloading vessel is utilized to handle the produced fluids.

**Safety**

- Safety concerns would include the close proximity of two vessels.

**Emergency Disconnect**

- ESD and EDS procedures apply to each vessel.
- The production fluid transfer line requires its own emergency procedures.

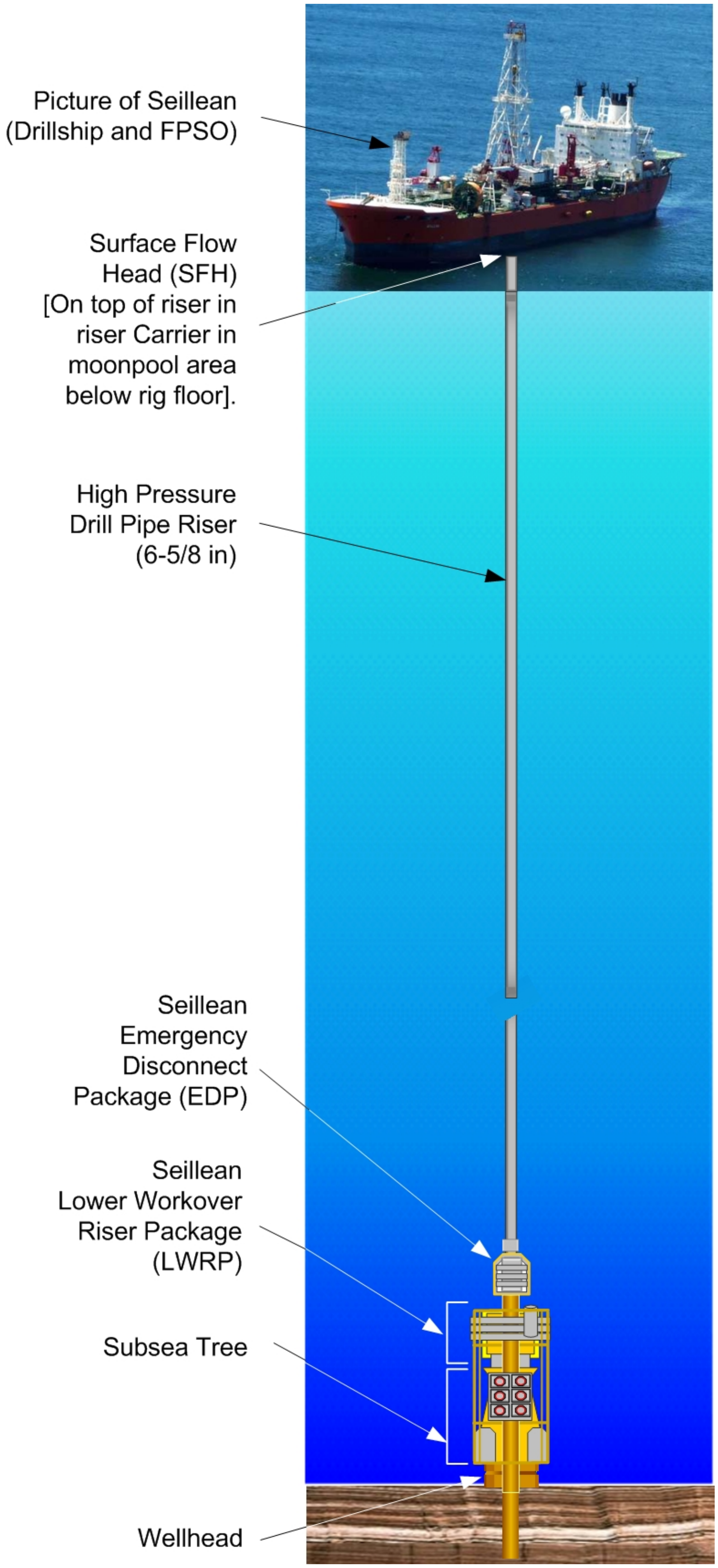



**Figure 10: Well Test System 4**

**Vessel**

- FPSO or FDPSO vessel with drilling capabilities. (Seillean vessel is shown in Figure 10; however, it is capable of riser handling, but has no drilling capabilities).
- DP capable.
- Existing technologies to areas outside USA, new technology for deepwater GoM.
- Generally specific to a region or completion capability.
- Reduced operating window (stress joint).
- Horizontal trees are not applicable for the Seillean riser system.
- Certification may limit vessel availability.

**Well Testing**

- Proven method for EWT. High mobilization cost for a short-term EWT.

**Riser**

- Currently used with single barrier 6-5/8 in riser. Single barrier risers offers less environmental protection in case of a ruptured or leaking riser than a dual barrier riser (pipe within a pipe).

**Safety**

- SFH will isolate the well from the surface.
- LWRP will isolate the wellbore at the seabed and disconnect the riser string via the EDP.
- A retainer valve must be installed to prevent riser content leakage with an emergency disconnect.

**Emergency Disconnect**

- Proven methods for well control and disconnection.
- Modern customary emergency disconnect package (EDP), controlled by the vessel.
- No SSTT.
- EDS system is controlled by the MUX. system via a cable connected to the EDP. Operational procedures are proven.

**Handling of Fluids**

- Capable of handling large volume of produced fluids.

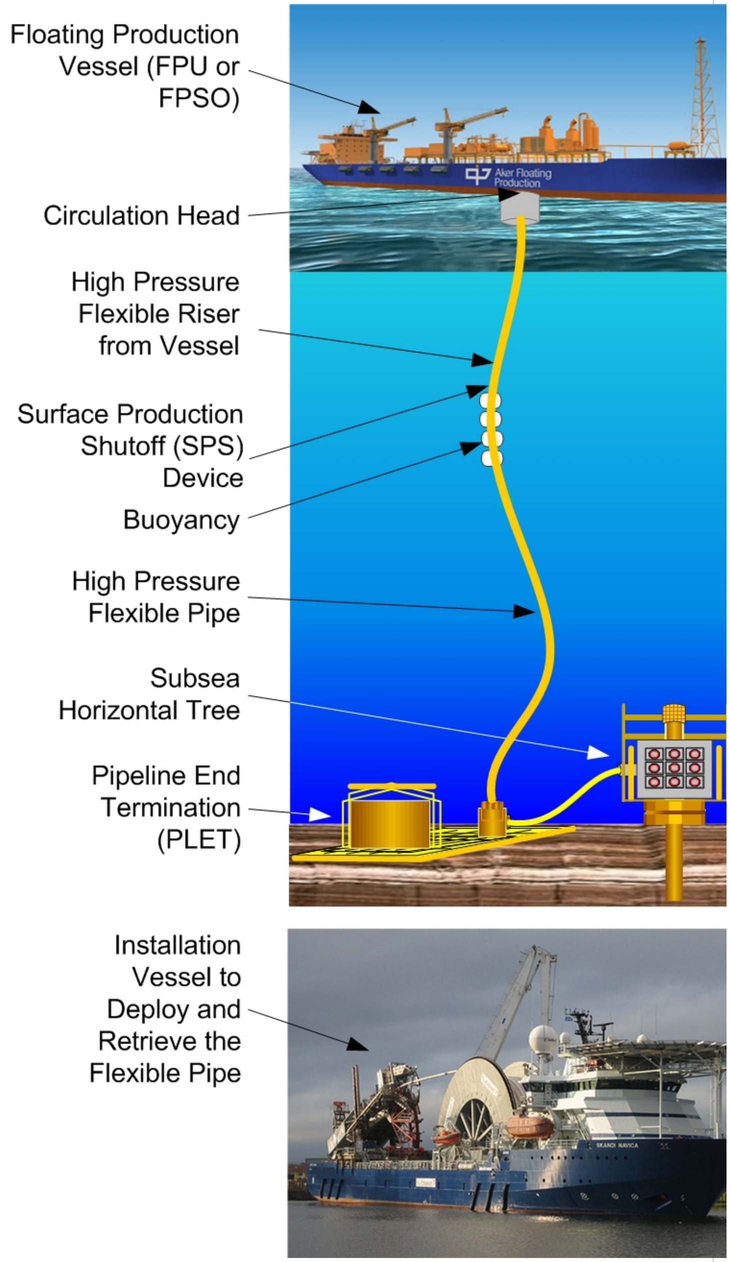



**Figure 11: Well Test System 5**

**Vessels**

- FPU or FPSO for well testing.
- Installation vessel needed to deploy and retrieve flexible pipe.
- DP capable.
- Existing technologies to areas outside USA, new technology for deepwater GoM.
- Reduced operating window.
- Control system handoff procedures may be an issue with two vessels.
- ROV support on the vessel is essential.

**Well Testing**

- EWT operations can only be conducted with completed production system.
- No ability to conduct well operations if required.

**Riser**

- High pressure flexible riser can connect to either a PLET or a Subsea Tree.

**Safety**

- Proven methods for well control and disconnection.
- Circulation head (primary surface control) and SPS for fluid containment at the breakaway (top and bottom) point on the riser.
- A master control station (MCS) on the FPU / FPSO will communicate with the subsea control module (SCM) on the tree for subsea well control.
- No SSTT, after EDS1, well control is with the vessel and not subsea.

**Emergency Disconnect**

- Vessel would disconnect from the riser at the surface.  Would need to reclaim the riser when it returns.
- Automated and Manual EDS established.

**Handling of Fluids**

- FPU / FPSO capable of handling large volume of produced fluids.

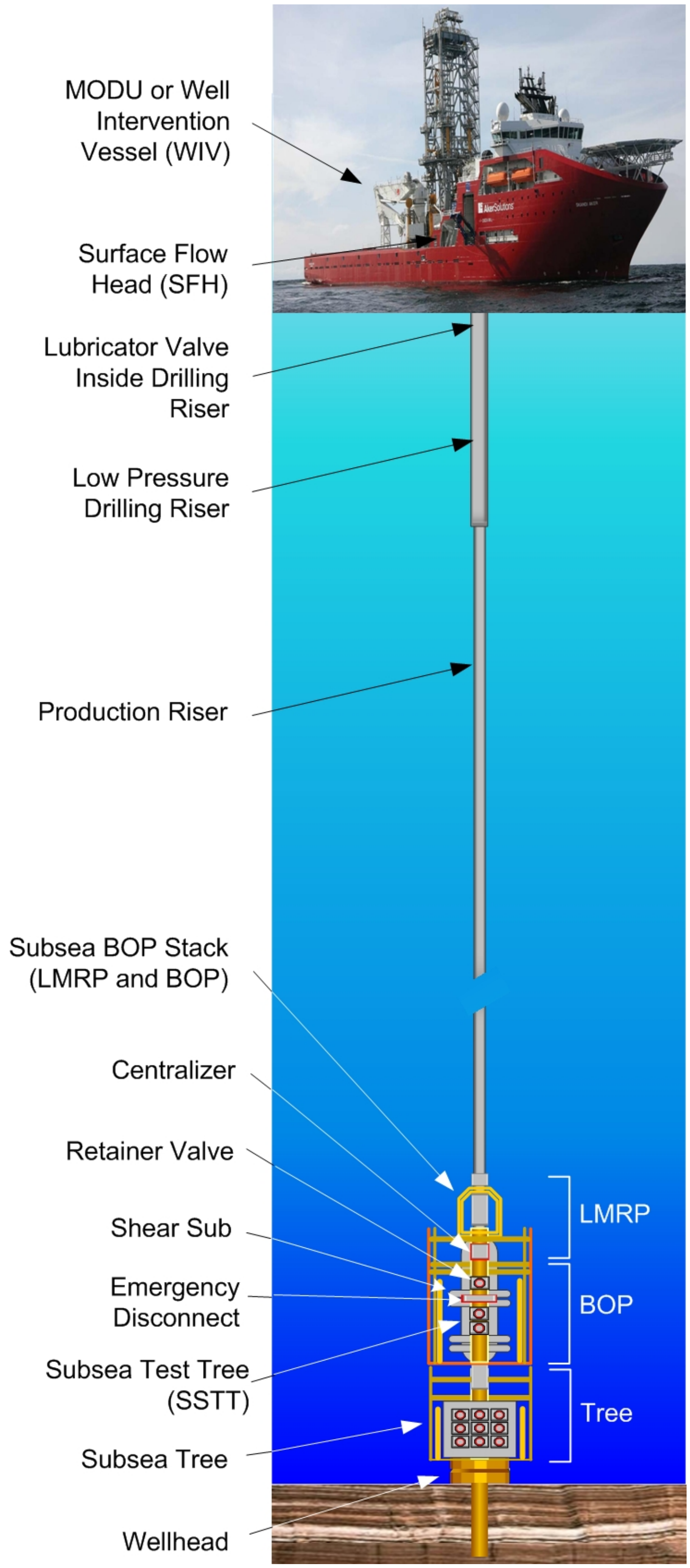



**Figure 12: Well Test System 6**

**Vessel**

- Standard MODU with 4th to 6th generation drilling equipment, or WIV.
- Proven system methodology.
- Established method of control.
- Package weight can be an issue on older tree systems.
- Control of subsea BOP via MODU's MUX system. A secondary acoustic system is preferable (and a requirement in certain countries).

**Well Testing**

- Limited storage determines test duration.
- Deck load and space are an issue.
- Run and latch landing string with (tubing hanging running tool [THRT] and SSTT).
- Surface mounted and production tree well control will be from well test contractor equipment.

**Riser**

- Lower cost drilling riser (low pressure).
- Can be used with single or dual barrier risers.

**Safety**

- Proven methods for well control and disconnection.
- Surface mounted and production tree well control will be from Well Test Contractor equipment.

**Emergency Disconnect**

- Emergency procedures are proven, although require complex handoffs with two vessels.
- Emergency disconnect scenarios require complex sequencing.

**Handling of Fluids**

- Limited hydrocarbon storage capability.
- Risks with temporary storage and gas.
- Equipped with flare booms.

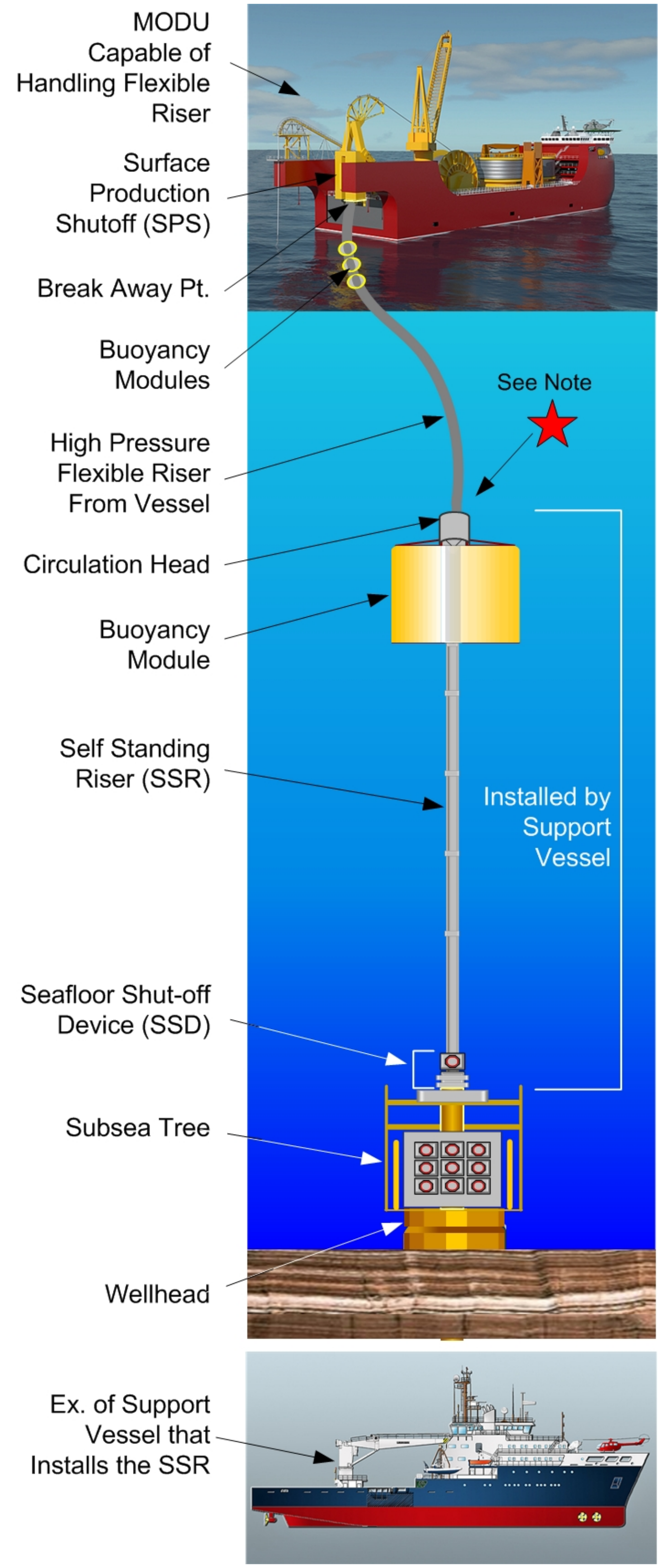



**Figure 13: Well Test System 7**

**Vessels**

- Intervention, MODU, or FPSO for well testing.
- Installation / support vessel to install SSR.
- Proven system methodology.

**Well Testing**

- Vessel storage determines test duration.
- ★ Circulation head connects to subsea lubricator for wireline or CT access. A surface test tree and BOP would be installed to shear and cut with an EDS.

**Riser**

- High pressure SSR, for either single or dual barrier risers.
- Analyzed for single barrier 6-5/8-in siser with 10,000 psi bore pressure and 20-ft diameter by 33-ft tall buoyancy module

**Safety**

- SPS to isolate well at the surface.
- SSD has two shear rams for well shut-in, and an ROV operated disconnect.
- Lower riser assembly is controlled via an ROV operated panel controlled from the surface or from stored energy in the accumulators.
- Umbilical junction box (UJB) supplies electric / hydraulic energy for SSD and subsea tree. UJB is deployed from the installation vessel.
- No SSTT; this system uses a stress joint above the SSD, instead of flex joint.

**Emergency Disconnect**

- Emergency procedures are proven, although require complex handoffs.
- EDS require complex sequencing.
- Circulation head assembly connects the production, kill lines, and control umbilical from the intervention vessel for emergency disconnect.
- In case of EDS and vessel drive-off, buoyancy modules on the flexible riser allow the vessel to retrieve the flexible riser and prevent the lines connected to the circulation head from being trapped on the SSR.

**Handling of Fluids**

- Deck load and space can be an issue.

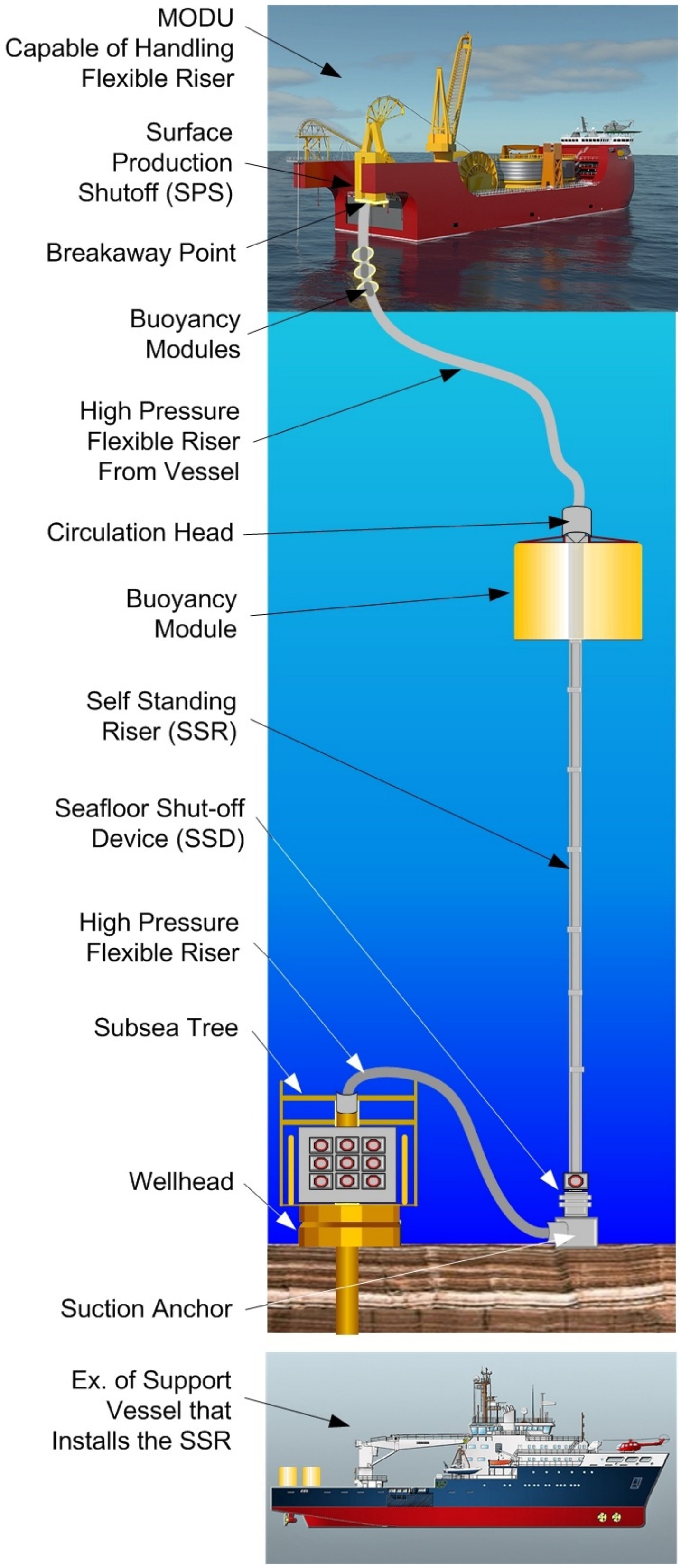



**Figure 14: Well Test System 8**

**Vessels**

- Intervention, MODU, or FPSO for well testing.
- Installation / support vessel to install SSR.
- Proven system methodology.

**Well Testing**

- Vessel storage determines test duration.
- Circulation head connects to subsea lubricator for wireline or CT access.

**Riser**

- High pressure SSR either single or dual barrier risers.
- Analyzed for single barrier 6-5/8 in Riser with 10,000 psi bore pressure and 20 ft diameter by 33 ft tall buoyancy module

**Safety**

- SPS to isolate well at the surface.
- SSD has two shear rams for well shut-in, and an ROV operated disconnect.
- Lower riser assembly is controlled via an ROV operated panel controlled from the surface or from stored energy in the accumulators.
- Umbilical junction box (UJB) supplies electric / hydraulic energy for SSD and subsea tree. UJB is deployed from the installation vessel.
- No SSTT; this system uses a stress joint instead above the SSD, instead of a flex joint.

**Emergency Disconnect**

- Emergency procedures are proven, although require complex hand offs.
- Disconnection scenarios require complex sequencing.
- Circulation head assembly connects the production, kill lines, and control umbilical from the intervention vessel for emergency disconnect.
- In case of EDS and vessel drive-off, buoyancy modules on the flexible riser allow the vessel to retrieve the flexible riser and prevent the lines connected to the circulation head from being trapped on the SSR.

**Handling of Fluids**

- Deck load and space can be an issue.

# 7 WELL TEST DESIGN AND SAFETY – DOWNHOLE AND SUBSEA

With any deepwater well testing procedure, operators must weigh the information or results to be gained against all the potential risk factors. The shear depth of the well control equipment coupled with underwater currents and surface weather conditions amplifies the safety hazards to personnel, the environment, and equipment. Taking the high cost associated with these operations along with the safety factors, it is critical to select the optimum well test design.

Well test design includes planning the downhole test equipment and subsea landing strings, spacing-out the SSTT in a BOP stack, and drafting the necessary surface equipment needed. This type of planning is required for ESD and EDS scenarios where assurances are needed to control the well and avoid hydrocarbon leakage. Well test planning must also address the surface equipment needed to handle the produced fluids (oil, water, and gas) safely while complying with regulatory agencies (Refer to Section 8).

This section describes some of the established technology needed for conventional deepwater well testing in the GoM. The selection of components is at the discretion of the operators and well testing contractors. The well test modeling results for the three reservoirs provide significant insight about the reservoir characteristics and fluid properties that help optimize the well test design. Different components of the downhole testing tools (i.e., DST string), landing strings, and risers needed to safely conduct well testing are presented from the lowest point in the wellbore, up to the surface.

## 7.1 DOWNHOLE WELL TEST STRING COMPONENTS AND FUNCTIONS

This section gives technical specification of typical DST string components that can be used for short-term (DST) and long-term (EWT) well testing in deepwater GoM. An example DST string is shown in Figure 15.

### Packer

A packer is run into a wellbore that expands externally to seal the wellbore. This isolates the test interval from the annulus (space in the tubing) allowing the reservoir to be tested. There are two types of packers, the production or test packer and the inflatable packer. Production or test packers may be set in cased holes and inflatable packers are used in open or cased holes. These may be run on wireline, pipe, or coiled tubing. Some packers are designed to be removable, while others are permanent. Packers must be capable of withstanding the shock from a perforating gun (i.e., Tubing conveyed perforating [TCP] gun).

### Safety joint

The safety joint provides an emergency release between the DST string and the packer.

### Ball Valves

Ball valves are used for downhole shut-in, and flowing test procedures, by selectively closing and opening the DST string to flow. When the DST assembly is run to depth and the packer set, applied annulus pressure causes the ball valve to rotate to the open position and allows full bore passage through the tool. The ball valve closes when the tool is cycled again.

### Circulating Valves

Circulating valves establish flow between the annulus and the DST string.  There are three functional positions; closed, reverse, and circulate.  The tool may be cycled as many times as required and can be used to displace fluids before a test, to spot fluids (nitrogen or acid) and / or to reverse circulate recovered fluids from the drill string.

### Slip Joints

Slip joints are added to the DST string to compensate for vessel movement in order to maintain constant weight while setting downhole tools.  After the test is underway, the slip joints compensates for any string expansion or contraction due to temperature or pressure changes.  At least two slip joints are normally run downhole.  This arrangement allows the DST string to expand or contract in either direction.

Slip joints usually have safety valves and reverse circulation subs installed to isolate the drillpipe and provide reverse circulation.  These tools permit passage of perforation tools and high volume flow rates.

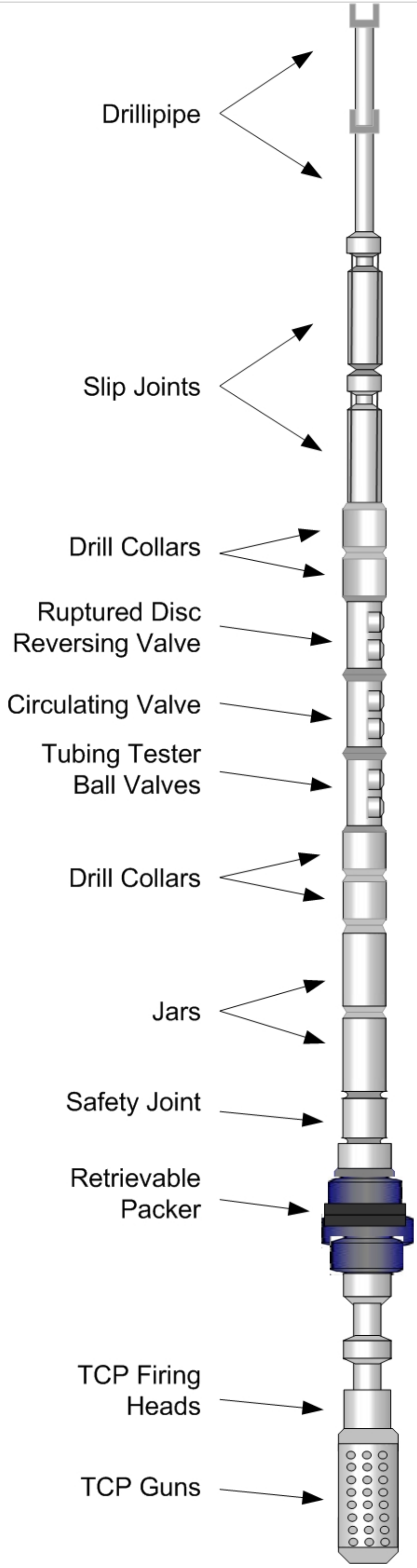



**Figure 15: Example of Downhole String**

Figure 15 illustrates a DST string used to quickly and safely evaluate a newly discovered hydrocarbon-bearing formation. The DST string is run after the well has been drilled and cased. The string is run downhole in conjunction with data gathering systems and fluid sampling methods. Many data gathering systems use wireless technology to transmit the BHP and temperature back to the surface real-time.

The DST string is deployed to perforate an interval inside the wellbore through the casing and allow produced fluids to flow to the surface through the space (annulus) in the tubing. Regardless of what type of DST string is used, it must have all the controls needed to shut-in and kill the well if necessary. The components in Figure 15 from bottom to top are:

- TCP guns and firing heads are used to gain access to the perforating depth.
- The packer is a device that can be run into a wellbore with a smaller initial OD that then expands externally to seal the wellbore.
- Safety joint can shut-in the well with over-pressure in the annulus.
- Jars are used downhole to deliver an impact load to another downhole component, especially when that component is stuck. Jars can either be hydraulically or mechanically operated.
- Ball valves are used for emergency shutdown. Tubing tester ball valves are also used to pressure test the tubing while running in the well.
- Circulating valves isolate the tubing and annulus. The circulating valve also enables circulation and reverse circulation through the tubing string and associated annulus to remove debris or change fluid weight.
- Tester valve obtains formation pressure as a fluid-loss control tool and a safety shut-in valve.
- Slip joints allow the string to contract and expand with temperature without affecting the internal pressure or volume.

## 7.2 LANDING STRING COMPONENTS FOR WELL TESTING

The landing string assembly is a safety system that can be latched to either the tubing hanger inside the wellhead or subsea tree. The landing string provides the dual barriers required for well testing.

When the landing string is latched directly to a wellhead or subsea tree, in an emergency, it can cut either wireline or coiled tubing and disconnect the riser system from the wellhead / subsea tree. If a BOP stack is present, the landing string will replicate the features of the BOP stack.

The components listed below and shown in Figure 16 are part of an enhanced landing string commercially available for deepwater GoM well testing with a subsea BOP stack. The string is comprised of the SSTT, shear sub, retainer valve, and lubricator valve. Figure 16 is an example of a landing string used for short-term and long-term well testing with a subsea BOP.

Deepwater EWT utilizing a surface BOP is new technology for the GoM. The latter part of this section gives a description of the surface BOP and its safety mechanisms.

### Subsea Test Tree

The SSTT replicates the functions carried out by the subsea BOP stack and EDS of a conventional system – cut wireline / coiled tubing, shut-in the well, and ensure emergency disconnect. The SSTT provides the primary dual safety barrier to contain well pressure and disconnect via two ball valves. One ball valve is used to cut the coiled tubing / wireline, leaving full redundancy for the other ball valve to seal the well. A latch mechanism allows the string to unlatch and re-latch as conditions require. The short overall length of the SSTT enable the two sets of BOP rams to close below the SSTT and the shear rams to close above the SSTT.

A secondary disconnect system will isolate the well in the event of total umbilical loss.

The SSTT interfaces with the running tool adapter at the lower end, and with the shear sub at the upper end.

### Shear Sub

The shear sub enables the BOP shear rams to sever the landing string in the event of an emergency disconnect from the well. It is positioned between the SSTT and the retainer valve. The correct position of the shear sub within the BOP stack ensures that the BOP shear rams straddle the *shearable* section of the landing string

### Retainer Valve

The retainer valve is located just above the BOP shear rams and is designed, in the event of an EDS, to isolate the landing string contents and vent trapped pressure from between the retainer valve and the SSTT to the riser. This minimizes the time it takes for an EDS which is essential for safety of personnel and equipment.

If the riser content is high-pressure gas, the retainer valve prevents the gas release and expansion into the riser. Without a retainer valve, the gas release and expansion would force the riser contents to the surface / vessel, and the external pressure could collapse the riser.

### Lubricator Valve

The lubricator valve is located below the rig floor and enables the safe deployment of either wireline or coil tubing equipment. The lubricator valve is a ball valve that provides bi-directional sealing, allowing pressure testing from above and well pressure control from below. Within the valve is a unique pump-through feature for well kill operations.

### Well Testing Components using a Surface BOP

Shallow-water well testing using a surface BOP with a jack-up rig / platform in the GoM is fairly common; however, conducting EWT in deepwater GoM using a surface BOP is a new concept. This technology is represented in well test System #2. The surface BOP is installed on a DP vessel that has all the customary modern equipment in regards to the surface BOP, well control, drilling equipment, and fluid management facilities.

The landing string consists of a seafloor shutoff assembly (SSA) latched to the wellhead that will shut-in the wellbore at the seabed and disconnect the riser string at the top of the SSA during an emergency.

The casing riser connects the SSA to the surface wellhead that is connected to the surface BOP in the moon pool area of the vessel. A slip joint (i.e., telescopic joint) connects the surface BOP to the vessel's diverter system under the rotary. The diverter system diverts hydrocarbons overboard and away from the drill floor and personnel in an emergency situation when the well cannot be controlled. The surface BOP uses service loops to connect the choke and kill lines to the vessel's EDS systems. A surface BOP does not have booster lines.

A surface flow head (SFH) is the last piece of equipment installed on the landing string. The SFH functions to isolate the well at the surface and provide the mechanisms to inject fluids into the well and allow fluids to flow from the well.

A risk with this system is that the SSA is the only well control equipment subsea to isolate and disconnect from the well in case of emergency – there are no redundant subsea safety features. After an initial EDS, the well is controlled by the vessel and not the subsea well control equipment. These risks are mitigated with the appropriate selection of equipment and proper operational procedures and communications.

In the event of an EDS, the riser is disconnected from the SSA at the riser connector. The SSA remains latched onto the wellhead via the wellhead connector which is operated by an ROV. If the vessel initiates an EDS, the DST string will be sheared at the SSA. A fishing exercise will be needed to retrieve the string when the vessel returns.

Benefits of the surface BOP include its ease and speed of deployment and recovery. In addition, the surface BOP can be re-deployed on different vessels providing greater cost efficiencies.

The biggest advantage with the surface BOP compared to a conventional subsea BOP, is that the operational water depth for the drilling rig / well testing vessel increases by at least 20%. This increase in depth is possible because the casing riser system and SSA are lighter, reducing the support and top tension needed for the topside equipment on the vessel.

Figure 17(c) is an example of a surface BOP system.

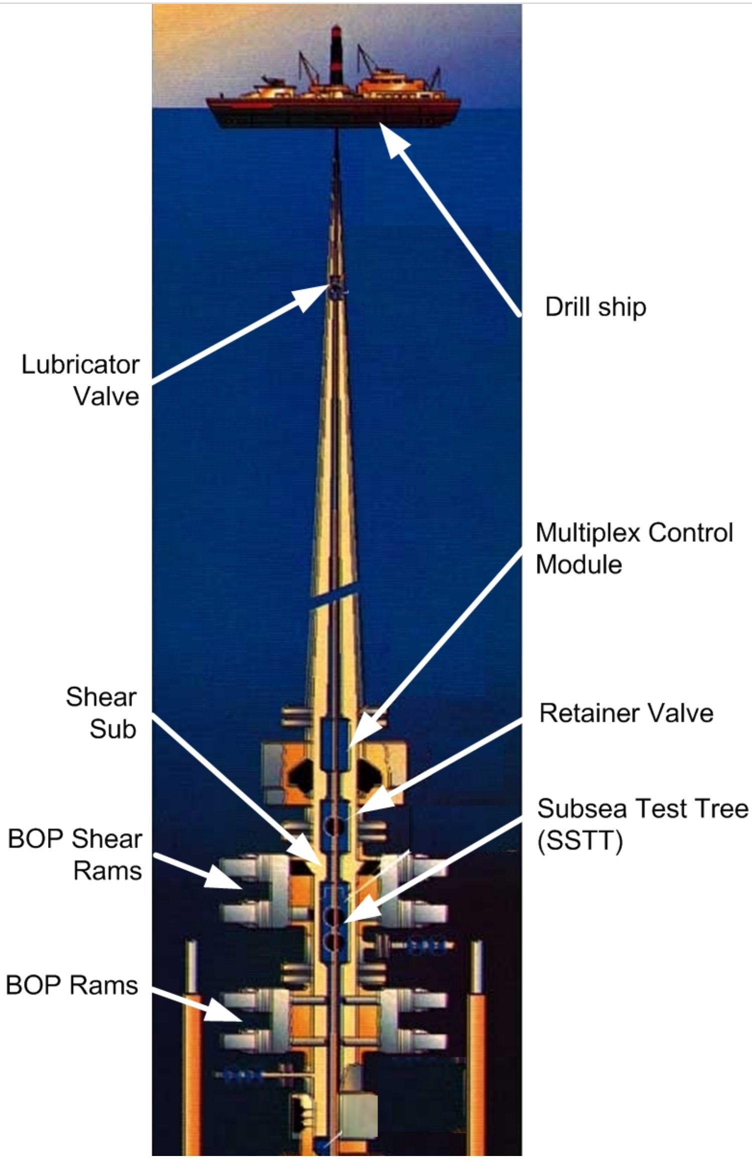



**Figure 16: Example of Deepwater Landing String**

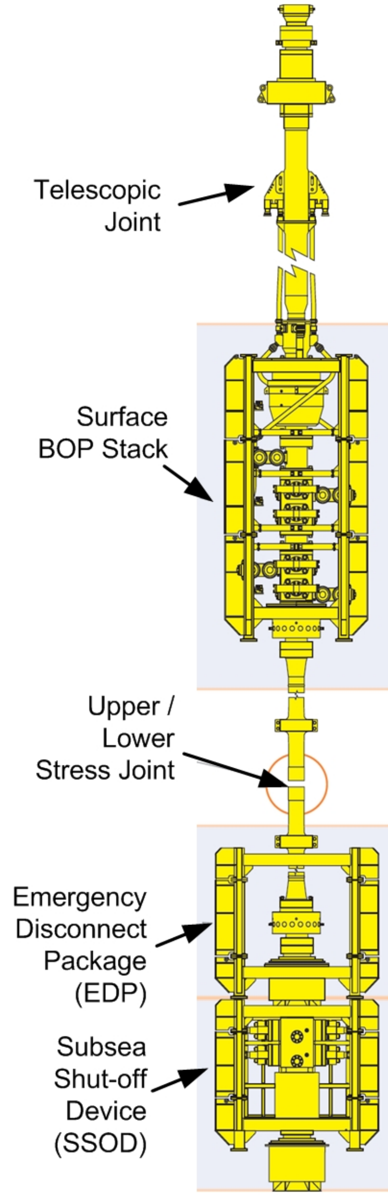



**Figure 17: Example of Deepwater Surface BOP System**

## 7.3 RISERS

### Conventional Riser System

Conventional risers (i.e., marine, casing, drillpipe) are also known as workover risers. A normal workover riser system includes a lower marine riser package (LMRP) with two shut-in shear valves, a retainer valve to ensure fluid remains in the riser during disconnect, and a riser string composed of joints. Power is supplied via umbilicals or a subsea hydraulic power unit (HPU). The riser size must be adequate for all wireline or coil tubing interventions planned, must meet or exceed the well's pressure rating, have appropriate connections for the sea conditions and water depth, and must be able to shear either the wireline or coil tubing.

Conventional risers are designed for specific fields with connections, pressure ratings, and interfaces specified to match the wellhead or subsea trees. Operators of large fields own their own risers suited for each field's well connections, water depth, and well conditions.

Workover risers are deployed joint by joint through a rotary table of a rig / vessel. Workover risers generally have one of three different connection types; threaded box and pin, union nuts, or quick connections.

**Threaded connections** – Are the least expensive and easy to rework but require torquing which can potentially degrade the sealing surface of the joint and limit the number of times it can be used. Threaded connections make it difficult to strap an umbilical or annulus pipe to the side of it, which is a common requirement for certain subsea trees or LMRPs.

**Union nuts** – Help protect the sealing elements since there is no turning. The union joints are stabbed straight together and only the union nut is torque, to provide the proper sealing force. Another benefit of not turning the entire joint is that annulus lines or umbilicals can be strapped to the side of each joint and made-up at the same time as the main joint. Union nut connections are difficult to rework.

**Quick connections** - often bypass torquing and use weight-set profiles that utilize special procedures, and sometimes special tools, to ensure proper make-up. This connection type is not quick and can be up to three times slower than other connection types, but does provide well-protected seals.

### Flexible Riser System

Flexible riser system is usually deployed and retrieved by a secondary (installation) vessel. The flexible riser is connected to the subsea tree which is surface controlled from the primary well testing (intervention) vessel. The intervention vessel will connect with the flexible pipe through the surface production system (SPS) on a suspended connection porch on the vessel. The SPS has a block valve for emergency disconnect. The upper end of the flexible riser has a block valve for fluid containment and buoyancy for recapturing after disconnection.

If the vessel initiates an emergency disconnect, it would disconnect from the flexible pipe at the surface and will need to reclaim the flexible pipe when it returns. Buoyancy modules attached to the flexible pipe close to the surface facilitates the reclaiming of the flexible pipe.

Flexible risers can be very heavy and the reels can take up a lot of deck space. With increased water depth, the appropriate surface equipment for handling the flexible pipe needs to be taken into consideration.

Inherently, flexible risers do not allow passage of the downhole string package. Most of the new subsea trees have provisions for recording pressures downhole and at the surface. It is the connection to the subsea tree that provides the pressure data to the surface. If the well is not equipped with the pressure sensors, then wireline / electric line sensors have to be installed before a flexible riser can be used for well testing.

**Self Standing Riser**

The SSR is a rigid system that is installed by a secondary, installation vessel prior to well testing operations that are conducted by a primary vessel. The SSR can be left unattended following installation or after completing well testing operations.

The subsea shut-off device (SSD) is the lowest point of the SSR and connects to either a wellhead, subsea tree, or to a seafloor anchor if the SSR weight cannot be supported by a wellhead or tree. The main purpose of the SSD is to shear the coiled tubing, wireline, or other tools to isolate the reservoir in case of an emergency.

An umbilical connects the primary vessel with the SSD and controls the shear and seal functions of the SSD from the vessel. The SSD also has ROV operated shear and seal valves in case communication via the umbilical is disrupted.

A stress joint above the SSD provides the transition between the flexibility of the SSR joints and the stiffness of the wellhead / subsea tree interface. The stress joint has a retainer valve to isolate the riser contents during emergency disconnect.

Depending on the design conditions for a particular application the SSR standard casing joints may require vortex induced vibration (VIV) suppression devices.

Above the standard casing joints, one or more buoyancy modules are installed. The elevation and number of buoyancy modules used is dependent on particular application and water depth. The uppermost buoyancy module must be sufficiently below the surface at low tide when left unattended, or following an emergency disconnect to avoid being a maritime hazard and to minimize wave loads on the riser system. The uppermost buoy must be able to withstand the ocean current drag, be protected from dropped objects, and have a circulation head to the riser extension and umbilical jumper from the primary vessel.

The SSR is equipped with instrumentation that actively measures the riser top tension and relays the information to the surface vessel. The information provides regular indications of the buoyancy module status and serves as an alarm to ensure the safety and survival of the system.

A flexible riser extension extends the riser casing from the buoyancy module up to the deck of the primary vessel. The flexible rise extension isolates vessel motions. There must be provisions to protect the flexible riser extension from changes in vessel heading. The riser extension has an emergency disconnect segment to seal the top of the SSR, shear the tubing, and release the vessel from the SSR.

Figure 13 (Well Test System # 7) and Figure 14 (Well Test System # 8) illustrate the SSR.

# 8 SURFACE EQUIPMENT FOR WELL TESTING

The well fluids (hydrocarbon flow) produced during a conventional well test (i.e., DST, EWT, and Interference well testing) must be handled using surface testing equipment when permanent production facilities are not available.

The well test modeling / simulations done on the three reservoirs in the GoM have provided valuable information that will facilitate the selection of the appropriate surface equipment needed.

For example, the modeling data showed that well test durations for the Paleocene reservoir were significantly higher than for the Middle Miocene and Eocene reservoirs. A short-term test and a long-term test in the Paleocene area were estimated at 24 days and 140 days, respectively. The large volume of fluids produced during these tests dictate the storage requirements for the vessel and whether an additional vessel is needed to offload.

The well test modeling provided cumulative gas and GOR for each reservoir. The Eocene reservoir had the highest cumulative gas and GOR. This type of information determines what type of surface facilities are needed to deal with the gas.

The pressure and flow rate at the wellhead varies among the three reservoirs. The modeling data provided information for pressure / velocity analysis specific to each reservoir. This provided initial estimates to optimize the flow as it travels from the wellhead through the surface equipment and piping on the deck of a vessel.

The surface testing equipment described below must perform a wide range of functions:

1. Quickly control pressure and flow rates at the surface and shut-in the well.
2. Accurately meter the fluids and collect surface fluid samples.
3. Separate the produced fluids into three fluid phases; oil, gas, and water.
4. Dispose of the resulting fluids in an environmentally safe manner.

## 8.1 SURFACE WELL TEST EQUIPMENT

The surface well test system is a combination of the following equipment and services:

### Surface Flow Head (SFH or Surface Test Tree)

The SFH is one of the critical safety devices for a well. It is used to quickly shut-in a well upstream of the choke manifold in case of overpressure, failure, a leak in downstream equipment, or any other well emergency requiring an immediate shut-in. It typically is equipped with a lift sub, a swivel which allows the test string to rotate, and temporary pipe work connections for the flow and kill wing valves.

### Emergency Shutdown System

The ESD system is a multi-station system located at different stations on the vessel that controls the flowline valve and the surface safety valve on the SFH. If activated, it closes these valves in response to an emergency.

### Solids Exclusion Equipment

The solids exclusion equipment is deployed close to the wellhead and upstream of the first well control device, usually the choke manifold. This removes solids, sand, mud, and drill cuttings from the produced fluids at high pressure to prevent erosion to the downstream equipment. Solids are usually stored in a dedicated or portable tank that requires offloading at a shore facility. Solids containment and disposal must be according to the CRETIB Code (Corrosive, Reactive, Explosive, Toxic, Flammable, and Biological-infectious – in reference to hazardous waste containment and disposal).

High permeability reservoirs, such as the Middle Miocene, usually have a lot of sand production which, if not removed, can cause serious erosion of downstream equipment.

### Choke Manifold

The choke manifold is the primary method to control the flow rate and reduce the pressure before the produced well fluids enter the processing equipment. The choke manifold controls the well flow through either a fixed or an adjustable choke.

### Heat Exchanger

During well test operations, flow is passed through a heat exchanger to raise the temperature of the fluid to prevent hydrate formation (ice), reduce viscosity (make it less *thick*), and break down emulsions for efficient separation of oil and water.

### Three-phase Separator

From the heat exchanger, hydrocarbon flow is directed to a three-phase separator. The separation process first drops the liquids phase (oil and water) out of the suspension, leaving the clean dry gas to be measured. The oil and water are then separated and measured. All parameters throughout the separation process are constantly monitored and measured with a data acquisition system.

The separator can operate as a stand-alone unit or with a multi-phase flow meter. When a multi-phase flow meter is used, flow measurements are unaffected by separation issues such as foaming oil, emulsions, and gas that remains in the oil line.

Figure 18 shows a typical deck layout of the surface equipment.

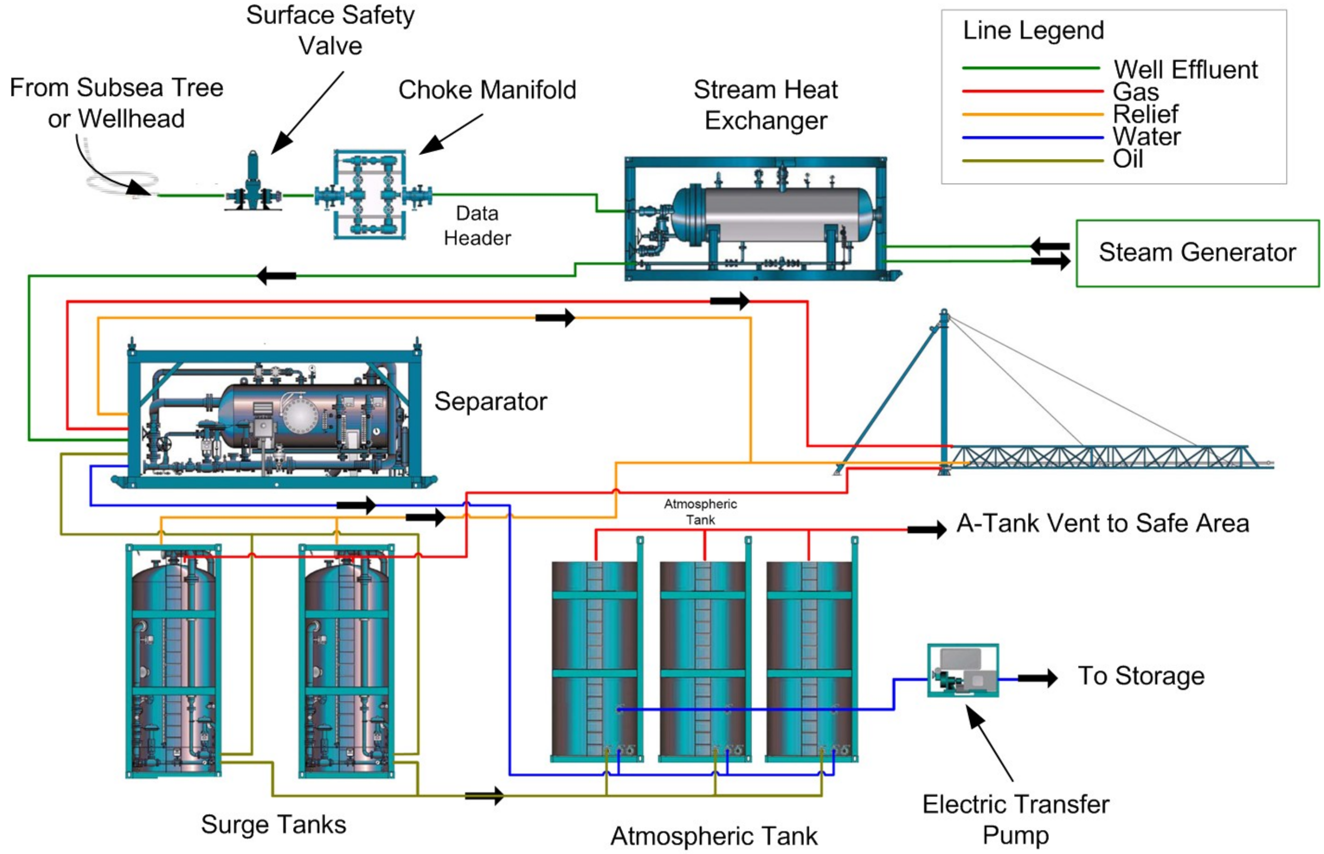



**Figure 18**
**Surface (Topsides) Equipment Layout**

## Produced Water System

The water separated out is called *produced water*. Because the water has been in contact with the hydrocarbon-bearing formation for centuries, it contains some of the chemical characteristics of the formation and the hydrocarbon itself. In the early appraisal stage, the oil production is high and water production is low.

The produced water leaves the separator vessel and is directed to a surge tank where it can be stored, accurately measured, and degassed prior to being stored in the stock tank. The stock tanks provide additional storage and the second stage of the oil-in-water separation process.

Produced water is not a single commodity. The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological formation, and the type of hydrocarbon product being produced. Produced water properties and volume can vary throughout the lifetime of a reservoir.

Produced water management practices are subject to all applicable federal and state regulatory requirements. As an alternative to water storage, transport, and onshore disposal, overboard produced water disposal may be permitted if a treatment package is used that ensures the disposal is environmentally safe. Testing for water quality prior to overboard disposal is essential.

Most U.S. offshore Operators discharge produced water to the ocean subject to all applicable regulatory requirements. Regulated by the Environmental Protection Agency (EPA), discharge requires U.S. offshore discharge permits. The offshore subcategory requires an oil and grease limit of 29 mg/l monthly average, and 42 mg/l daily maximum. In addition to the national oil and grease limit, the EPA regional offices impose other discharge limitations, including restrictions on flow rate, toxicity testing, and monitoring for several toxic metals, organics, and naturally occurring radioactive material. Most of the treatment technology for offshore produced water is geared toward removing oil and grease.

### Flare Burners

If the oil and gas flows are not stored or off-loaded, these flows can be directed to flare burner for disposal. The burners must be kept at a safe distance from the vessel in order to reduce heat radiation exposure to personnel and fire risks. Utilizing the latest advances in burner technology reduces the noise exposure levels and minimizes smoke and fall-out pollution.

Flare burning has environmental impacts to the air, sea, and commercial impacts – flaring a valuable product, possible fines, and public image.

Flare curtain systems are fed by seawater pumps installed and independent from other fire systems on the vessel. These curtains, typically two, reduce the heat radiation and fire risks. The gas that flows into the flare must be oil free. The length of the boom as well as the size of the flare tip is determined by the expected GOR.

In cases where produced crude is flared, lower API crude is preferred, if not regulated. The efficiency to burn crude with a low API grade has been achieved by using a steam exchanger to heat up the crude before the crude is routed to the burner. Requirements for off-loading the produced fluids are described in Section 8.2.

On May 19, 2010, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) established new regulations addressing issues such as production rates, burning oil, and the venting and flaring of natural gas. (Details in Appendix A – *Fed Reg Vol 75 No 74.pdf*)

Figure 19 shows an FPSO vessel with topside equipment and flare burning with a flair curtain.

**Figure 19**
**Example of the Surface Vessel Equipment and Flare Burning with a Flare Curtain**

## 8.2 DYNAMIC POSITIONING VS. MOORED SYSTEMS

DP capability defines a DP vessel's station-keeping ability under given environmental and operational conditions. Each of the eight well testing system designs utilizes a DP vessel. However, moored systems may be used for vessels like a MODU or FPSO, but this is not recommended for well intervention and service vessels that have to be DP moored in deepwater operations.

A DP system includes a control system with controllers, reference systems, sensors, network and operator stations. The DP system also has a power generation and distribution system that provides the thruster system with power which is controlled by the control system.

In order to obtain a DP-2 Class notation, a sufficient number of thrusters must be installed to meet the requirement of maintaining station keeping in the event of a single-point failure. The worst case single-point failure is in a power distribution system containing two high voltage switchboards where the loss of one switchboard causes the loss of 50% of the thrusters. DP capability analysis determines a DP vessel's ability to withstand environmental forces.

A DP-2 vessel must comply with the requirements as laid out by IMO and the class society of where the vessel located in class, ABS, DNV, BV, Lloyds etc. There are additional requirements issued by API, and for MODU vessels, there is a MODU code to take into consideration.

For moored vessels, updated guidelines after the devastating hurricanes in the GoM, have increased the number of required mooring lines for operations in the GoM, from eight to 12 lines. A significantly higher cost is associated with the operations of a conventional anchored mooring system. The anchored vessel will be most effective if a number of wells subject for well testing are located within the anchor pattern of the vessel, eliminating the need for costly relocations between the wells.

## 8.3 OFFLOADING OF OIL OR PRODUCED WATER

With well testing, if the vessel is not capable of storing the produced fluid it may need to be off-load to another vessel. Pumps are used to transport the crude oil or oily water to barge or tanker via a flexible hose. Especially with EWT, it is very important to have a redundant pump in case the first pump fails so that well testing operations can continue.

Due to the nature of the products to pump, as well as where the pumps are located (i.e., within the hazardous area on the deck), the export pumps must comply with explosion proof requirements / regulations, NEMA (National Electrical Manufacturers Association), and the Classification Society Standards and Requirements.

An alternative of disposing oily water is to re-inject the waste water into industrial waste / source wells. The equipment for this type of disposal has been installed on exiting vessels and has proven to be time and cost effective. The fluids are returned to the source via high-pressure injection pumps.

## 8.4 ANALYSIS AND SIMULATION OF WELL TEST SYSTEM VESSELS

Detailed analysis and simulation modeling was done on three typical vessels that could be used in the eight different well test systems. The analysis and simulation work for the three vessels were further divided into the different characteristics that are found in the three reservoirs. This work was conducted on the CR Luigs (drillship), Noble Paul Romano (semi-submersible), a MARECSA DP 2 FPSO (which includes the Toisa Pisces, Bourbon Opale, ECO-111, or using a conceptually designed Well Testing Service Vessel (WTSV) prepared for this study). Figure 20 illustrates these vessels.

Table 9 shows the main reservoir parameters used in the analysis and simulation work.


**Figure 20**
**Vessels used for the Analysis and Simulation Work**

| **Table 9**<br>**Reservoir Parameters for Three Typical Vessels for Well Test Analysis** | | | |
|---|---|---|---|
| **Parameter** | **Middle Miocene** | **Paleocene** | **Eocene** |
| Gas (MMscf/d) | 6 | 0.9 | 5.4 |
| Oil / Condensate (bbl/d) | 6,000 | 3,000 | 3,000 |
| Water (bbl/d) | 0 | 0 | 0 |
| Estimated GOR(scf/stb) / CGR | 1,000 | 300 | 1,800 |
| CITHP Pressure (psia) | 6,500 | 3,200 | 2,700 |
| CITHP Temperature (ºF) | 145 | 104 | 114 |
| CITHP = Closed in Tubing Head Pressure | | | |

The analysis included:

- Deck layouts for well equipment.
- Hazardous zones identification.
- Safety analysis for emergency shutdown.
- Pressure relief devices.
- Pressure and velocity analysis for the produced fluids (oil, gas, and water).
- Pipeflo schematics for the produced fluids traveling through the vessel equipment.
- Deck loading capacity for the equipment.,
- Flaresim models to look at the noise, radiation, and temperature effects under 0 mph and 30 mph wind conditions.

# 9 VESSELS IN THE GOM

## 9.1 RAMIFICATIONS OF THE US JONES ACT

One of the main restrictions for using foreign vessels for deepwater testing is the Jones Act, which restricts the flag and construction of vessels operating in U.S. waters. Vessels need to be U.S. flagged and U.S. constructed in order to operate in the U.S. GoM, unless special concession is obtained.

In order for a foreign vessel to perform work in the GoM, the following procedures / requirements must be met:

1. Customer contacts - U.S. Customs and Border Patrol (USCBP) port of entry branch defining the well intervention work to be performed.
2. If well intervention is covered by the US Coast Guard laws (includes Jones Act) then a U.S. vessel will be needed to perform the Job, otherwise a non U.S. flagged vessel is allowed to perform the well intervention.
3. If there are no U.S. flagged vessels capable or available for the work, the company needs to get a *Jones Act* waiver for the foreign flagged vessel to perform this work. This waiver will specify in detail the scope and limitations of work.
4. In the event the foreign flagged vessel (with the Jones Act waiver) needs to be retro-fitted with modular equipment in a U.S. yard (wireline / slickline unit, ROV, tanks, etc.), it will be allowed to proceed with the well intervention work only if the foreign flagged vessel returns to the same U.S. yard to uninstall equipment once the well intervention is finished.

## 9.2 VESSELS CURRENTLY IN THE GOM

Table 10 briefly describes some of the vessels capable of well testing in the GoM. Table 11 provides a comparative chart of six FPSO vessels world-wide.

**Table 10**
**Example Vessels in the GoM**

| Vessel Type | Vessel Name / Description | Example Vessel Picture |
|---|---|---|
| MODU Configuration – Well testing proven | Q4000 - Drilling system capable, could be configured for surface BOP but cost prohibitive |  |
| | Uncle John - Proven, flexible intervention and testing vessel | Uncle John |

**Table 10**
**Example Vessels in the GoM**

| Vessel Type | Vessel Name / Description | Example Vessel Picture |
|---|---|---|
| Well Stimulation / Storage Configuration. Potential for well testing with additional equipment. | Chloe Candies<br>DeepSTIM,<br>DeepSTIM 2,<br>DeepSTIM 3<br>HOS Hawke,<br>HOS Centerline<br>BJ Blue Ray<br>Blue Dolphin | <br>Chloe Candies |
| Intervention Vessels capable of well testing with modification | Southern Hercules<br>DMT Diamond<br>HOS Strongline<br>HOS Iron Horse<br>Bold Endurance<br>Specific | <br>Bold Endurance |
| Intervention Vessels | Olympic Intervention IV | <br>Olympic Intervention IV |
| Offshore Services GoM dedicated FPUs | BW Pioneer (Cascade Chinook for Petrobras, but has a flexible turret design for conversion).<br><br>Helix Producer 1 (can conduct well testing with minor modifications). | <br>BW Pioneer |

**Table 11**
**Comparative Chart of Six DP2 - FPSO Vessels Worldwide**

| VESSEL: | BW CARMEN | BOURBON OPALE | TOISA PISCES | ECO III | FPSO SEILLEAN | FPSO MUNIM |
|---|---|---|---|---|---|---|
| Length overall: | 101.00 m | 90.70 m | 103.67 m | 117.00 m | 249.7 m | 252 m |
| Class Society: | DNV | DNV | DNV | ABS | Lloyd's Register | ------ |
| Accommodation (persons): | 40 to 56 | 50 | 70 | 54 | 85 | 55 to 75 |
| Flag: | Norway | Mexican | Liberia | Mexican | Panama | ------ |
| Year of Building: | 1999 | 2004 | 1997 | 2007 | 1989 | ------ |
| Type of ship: | FPSO | FPSO | FPSO | FPSO | ------ | ------ |
| Gross tonnage: | 6,900 | 3,829 | ------ | 7,224 | ------ | ------ |
| Net tonnage: | ------ | 1149 | ------ | 2591 | ------ | ------ |
| Crude oil storage capacity: | 6,600 $m^3$ | 10,500 bbl | 24,500 bbl | 55,000 bbl | 310,000 bbl | 94,763 $m^3$ |
| Drilling / Oily water capacity: | 26,000 bbl | 3,600 bbl | 8,000 bbl | ------ | ------ | ------ |
| Maximum capacity (inlet): | 40,000 BPD | 15,000 BPD | 20,000 BPD | 15,000 BPD | 25,000 BPD | 125,000 BPD |
| Maximum gas flare capacity: | 50 MMscfd | 26.70 MMscfd | 31.80 MMscfd | 32.00 MMscfd | ------ | ------ |
| Design: | NACE ($H_2S$) | NACE ($H_2S$) | NACE ($H_2S$) | NACE ($H_2S$) | ------ | ------ |

# 10 CONCLUSIONS

Past deepwater exploration and development has proven billions of barrels of oil worldwide, with the potential of billions of barrels of oil with new discoveries. The three main areas for the deepwater discoveries are Brazil, West Africa, and the GoM. The focus of this study is the GoM.

With all exploration endeavors, the big fields are discovered first followed by the medium sized and smaller fields. Deepwater exploration has followed this trend, mainly because of the advancements in seismic technology, especially processing, and advances in drilling, subsea completions, and flow assurance. The reliance on seismic interpretations, electric logs, and MDTs has formed the basis for the appraisal of a discovery along with appraisal drilling. However; many deepwater wells have been drilled that have not met the production and reserve estimates and expectations. Because of these costly disappointments, operators are willing to commission only the larger fields (i.e., 200 MMBOE or greater) for commercialization in deep water.

The fact, as this study had shown, is that most companies do not know the size of the discovery and have done a poor job of estimating reserves (i.e., electric / wireline logs and MDT data only provide information in close proximity to the wellbore and seismic data cannot define the heterogeneity of the reservoir). Without knowing the size and production potential of a discovery, the consequence is that hundreds of millions of barrels of potential commercial reserves discovered in the GoM and in other deepwater regions of the world will not be produced because the risks are too high.

Operators recognize the only way to *ground truth* reservoirs is by conducting short-term and long-term well testing. These tests integrate all the reservoir properties away from the wellbore to give the permeability and net producing intervals (true kh value), location of reservoir boundaries, compartment volumes, reservoir energy, and initial reservoir pressure, etc. For deep water and ultra-deep water, early reservoir appraisal challenges include the high costs, operational and environmental risks, and the multi-disciplinary coordination associated with well testing operations.

Operators must manage the subsea requirements for well control, subsea equipment operations, and getting the flow from the well via some riser system – connected to a wellhead or subsea tree, to some type of processing vessel. These activities require many different engineering and operational disciplines. Operators, knowing the complexity involved, requested a more integrated look at early reservoir appraisal utilizing well testing systems.

The intent of this study was divided into two parts — the first part would be reservoir oriented and the second part would focus on the well test design and operations. The overall key points of this study are given in the executive summary. Experts in the fields of reservoir engineering, transient well testing, drilling, subsea equipment, risers, well testing, facilities, and production all made significant contributions in time, expertise, and documentation for this study. This final report summarizes the ~150 megabytes of text, tables, drawings, and figures produced by the team of experts. The entire content of these results can be accessed via the RPSEA website for this project.

During the reservoir investigation phase, two major surprises occurred:

1. The common assumption has always been that high production rates were needed to test the three GoM types of reservoir plays (Middle Miocene, Lower Tertiary, and Eocene). This proved not to be true. Numerous well test simulations showed that production rates between 1,000 BOPD to 2,000 BOPD would give the necessary pressure versus time results to do the classical pressure transient analysis. This discovery indicates smaller facilities and storage are required. In other words, deepwater testing can be done less expensively, and in less time.
2. During the simulation studies, the operating steering committee suggested looking at fluid injection tests. A representative set of injection well test simulations (fluid injection and pressure fall-off) yielded the same end results as the production and build-up tests. The industry experts attending the TRL workshop supported this conclusion and recommended doing more work to prove the technical and operational viability of injection testing in deep water. This could lead to an eventual field test on a GoM well. Plans are in progress to accomplish these recommendations.

The second part of the study identified eight well testing systems that can be used deep water. The team of experts at the TRL workshop confirmed the eight systems were viable and feasible, including the SSR systems.

The results of this study, and the sheer volume of data produced, have formed the basis for a software tool that will assist the various technical disciplines and management to make more informed decisions on well testing and reservoir characterization.

A template of an algorithm for this tool, showing the equipment needs for each well testing system was developed and will be the basis for a follow-on commercial enterprise. This algorithm takes the megabytes of information and arranges it in such a manner that the variety of engineers planning a deepwater well test can select a system, identify the equipment requirements, and with the addition of costing data / estimates, future work in progress, will be able to define and cost out the entire well test design. It will match the parameters of each reservoir type so that certain options can be eliminated or others more closely considered. Refer to Appendix C for a preliminary representation of this template.

This tool will provide engineers (i.e., either training for deepwater operations or with the experience for well test design) invaluable information and guidance not publically available in such an integrated format.

The outcome of this study fulfills the initial goal to evaluate deepwater well testing for the GoM and shows in detail the eight possible well testing systems, with a focus on risk reduction to personnel, the environment, and equipment.

Finally, it is clear that in some cases there may be a better way (i.e., risk and cost reduction) to do deepwater well tests which is via injection tests using the SSR concept. Only future analysis and field testing will confirm this.

# APPENDIX A - LIST OF DOCUMENTS USED TO DEVELOP THIS FINAL REPORT

**Table Appendix A:**
**Project 2501 Documents Submitted by Subcontractors**

| Sub-contractor | Document Title | Document Description |
|---|---|---|
| Univ. of Tulsa and Nautilus. | Task 2 Technology Status Assessment for RPSEA 2501. Provided an up-to-date review of deepwater well testing. Industry articles and publications, interviews with subject matter experts were all used to compile the report. | Document No.: 2501-TASK2.001 |
| Knowledge Reservoir<br><br>Section 4 | This document is the completed Task 5 report on the reservoir descriptions, characterizations, and well testing simulation results (DST, EXT, Interference, Injection testing, and Nodal Analysis. | Task 5 Reservoir Well Testing - Document No.: 08121-2501-02.05.Final. |
| Intecsea<br><br>Section 7.3 | Riser System Investigation – Workover riser system handling, deployment, and performance for conventional risers. | Project 2502 Riser System Investigation.doc |
| GMC<br><br>Section 6.2, 7.1, and 7.2 | Operational Issues for Well Test Systems 1 through 8.<br>Operational review with a focus on the equipment, handling, and control. These reports also include testing of the equipment prior to inclusion in the landing string, well startup, monitoring and control of the well test equipment, and areas of concern for each system. | Project 2502 Operational Issues System 1.doc<br>Project 2502 Operational Issues System 2.doc<br>Project 2502 Operational Issues System 3.doc<br>Project 2502 Operational Issues System 4.doc<br>Project 2502 Operational Issues System 5.doc<br>Project 2502 Operational Issues System 6.doc<br>Project 2502 Operational Issues System 7.docx<br>Project 2502 Operational Issues System 8.doc |
| GMC<br><br>Section 6.2, 7.1, and 7.2 | Control Philosophies for Well Test Systems 1 through 8.<br>These reports detail the primary and secondary methods of well control, including detailed control system matrices for each system, and principle modes of operations. | Project 2502 Control Philosophies System 1.doc<br>Project 2502 Control Philosophies System 2.doc<br>Project 2502 Control Philosophies System 3.doc<br>Project 2502 Control Philosophies System 4.doc<br>Project 2502 Control Philosophies System 5.docx<br>Project 2502 Control Philosophies System 6.doc<br>Project 2502 Control Philosophies System 7.doc<br>Project 2502 Control Philosophies System 8.doc |

| Table Appendix A: Project 2501 Documents Submitted by Subcontractors | | |
|---|---|---|
| **Sub-contractor** | **Document Title** | **Document Description** |
| GMC<br><br>Section 6.2, 7.1, and 7.2 | Emergency Disconnect Sequences (i.e., EDS 1, EDS 2, and EDS 3) for Well Test System 1 through 8.<br>EDS for extended well test equipment focusing on the surface flow head to the wellhead. These reports detail manual and automatic EDS procedures and provide detailed flowcharts for each EDS scenario. | Project 2502 Emergency Disconnect Sequences System 1.doc<br>Project 2502 Emergency Disconnect Sequences System 2.doc<br>Project 2502 Emergency Disconnect Sequences System 3.doc<br>Project 2502 Emergency Disconnect Sequences System 4.doc<br>Project 2502 Emergency Disconnect Sequences System 5.docx<br>Project 2502 Emergency Disconnect Sequences System 5.docx<br>Project 2502 Emergency Disconnect Sequences System 5.docx<br>Project 2502 Emergency Disconnect Sequences System 8.docx |
| EXPRO<br><br>Reference Section 8.4 | Well Test Design Reports: Analysis and Simulations on the vessels for Well Test System 1 through 8.<br>Vessels - CR Luigs, Noble Paul Romano; MARECSA DP 2 FPSO.<br>Data included Flowing Parameters, Process Flow Diagrams, Process and Instrumentation Diagram, Safety System Summary. Process Line Data Sheets, Safety Analysis Functional Evaluation, Safety Analysis Tables, Safety System Data Sheets, Pressure and Velocity Analysis, Pressure Drop Schematics, System Relief Summary, Deck Loading, and Flaresims. | WTDR_Project_2501_System1.pdf<br>WTDR_Project_2501_System2.pdf<br>WTDR_Project_2501_System3.pdf<br>WTDR_Project_2501_System4.pdf<br>WTDR_Project_2501_System5.pdf<br>WTDR_Project_2501_System6.pdf<br>WTDR_Project_2501_System7.pdf<br>WTDR_Project_2501_System8.pdf |
| EXPRO | Provided cost estimates to to perform short-term and long-term well testing in relation to planning, surface equipment preparation, mobilization, rig up and rig down, and demobilize. | Costs & Timeline.pdf |
| EXPRO<br><br>Section 7.1 and 7.2 | Downhole and Subsea Equipment (i.e., DST String and Landing String) | Wireline Overview.pdf<br>DST and LSA Overview.pdf |
| EXPRO | Vessel Safety Procedures | Operation Planning.pdf |
| EXPRO | BOEMRE Regulations | Fed Reg Vol 75 No 74.pdf |
| Intecsea<br><br>Section 7.3 | Well Testing SSR Design – This report covers the entire analysis done by Intecsea on the SSR. | 12122301-RPT-RS-0002-B-_Well_Testing_Riser[1].pdf |
| GMC<br><br>Section 9.2 | These documents cover the vessels in the GoM. The list includes vessel name, owner, capabilities, storage, riser type, ROV, derrick, moonpool, crane, mooring system and other capabilities | Well Intervention Vessel Matrix GOM.xlsx<br>Dedicated Well Intervention Vessels GOM.xlsx |

| **Table Appendix A: Project 2501 Documents Submitted by Subcontractors** | | |
|---|---|---|
| **Sub-contractor** | **Document Title** | **Document Description** |
| MARECSA | These documents provide detailed descriptions of a *proposed* well test service vessel DP2 FPSO.<br>Descriptions include the layout, equipment, structural arrangement, accommodations, piping, electrical and electronic systems, and process equipment.<br>A detailed DP capability analysis was performed, and very detailed general arrangements of the well testing equipment were drawn.<br>MARECSA also provided a detailed comparative chart of the current seven DP2 FPSO vessels worldwide. | WTSV-1011-05-001.pdf<br>WTSV-1011-02-001 REV.E SHIP DESCRIPTION.docx<br>WTSV-1011-02-003_REV C STATE OF THE ART.docx<br>WTSV-1011-02-002 (DP PLOTS).pdf<br>WTSV-1011-17-004 REV B 1 de 1-Model.pdf<br>WTSV-1011-17-001 1 de 1 REV E-Model.pdf<br>WTSV-1011-17-002 REV B 1 de 1-Model.pdf<br>WTSV-1011-17-003 REV B 1 de 1-Model.pdf |
| Nautilus | Seillean based material used as reference material for Well Test System 4. Provides specific information on well testing in Brazil. | DPR 2500.ppt<br>Heavy Crude Production in Brazil.pdf<br>plant overveiw.dwg<br>Process plant.rtf<br>Siri - Offloading System.pdf<br>003-7383 Prices Conditions offloading system.pdf<br>003-7383 Technical specification offloading system.pdf |
| Peter Lovie | The Technology Readiness Level (TRL) assessment provides the maturity status of the major components comprising each well test system. The TRL identified where further technical development is required for each system to enable its operation or to improve the projected performance of each well test system. | 1_Project_2501_Task_6.3_-_Final_Report_+_references_1-5_31Mar11.pdf<br>2_Project_2501_Task_6.3_-_References_6-9_for_Final_Report_31Mar11.pdf<br>2_Project_2501_Task_6.3_-_References_6-9_for_Final_Report_31Mar11.pdf |
| Nautilus | Business Case and Commercialization Plan:<br>Developed business case and commercialization plan for mobilizing the respective well test systems to a field ready status. It describes future plans for field testing to commercialize System 7 and System 8, further define requirements for field testing deepwater injection tests, and describes the efforts to develop a software modeling tool. | Complete |

# APPENDIX B - DEFINITIONS FOR THE TECHNOLOGY READINESS SCALE

**Table Appendix B:**
**The Technology Readiness Matrix**

| | TRL Designation | | Definition |
|---|---|---|---|
| Conception | TRL 0 | Unproven Idea (paper concept, no analysis or testing) | At TRL 0, a technical need has been identified and a concept has been conceived. The description of the technical need is general in nature without specific performance or functional requirements. The concept has been refined to the point that the physical principles have been documented and simple sketches, if applicable, have been produced. No analysis or testing has been performed. |
| Proof-of-Concept | TRL 1 | Proven Concept (functionality demonstrated by analysis or testing) | At TRL 1, the concept has been refined to the point where the basic physical properties (dimensions, material types, rates, etc.) have been developed and documented and preliminary drawings, if applicable, have been produced. The primary technical requirements are documented. Analysis and/or testing have been performed demonstrating that the concept functions as conceived. The testing may be conducted on individual subcomponents and subsystems without integration into a broader system. The concept may not meet all of the technical requirements at this level, but demonstrates the basic functionality with promise to meet all of the requirements with additional development. |
| | TRL 2 | Validated System Concept (breadboard tested in “realistic” environment) | At TRL 2, the concept is developed into an ad-hoc system of discrete components (breadboard/mock-up) to establish that the components work together prior to prototype construction. The system validates that it can function in a “realistic” environment, with the key environmental parameters simulated. Appropriate material testing and reliability testing may be performed on key parts or components. |
| Prototype | TRL 3 | Prototype Tested (prototype developed and tested) | At TRL 3, the technical specifications are developed further and a prototype has been developed. The technical specifications include details of the performance, functional, environmental, and interface requirements. The prototype is tested in a robust design development test program over a limited range of operating conditions to demonstrate its functionality. Reliability growth tests and accelerated life tests may also be performed. The relevant lab test environment may not be field realistic. This is an isolated test program for this technology, without its integration into a broader system. |
| | TRL 4 | Environment Tested (prototype tested in field realistic environment) | At TRL 4, the technology meets all of the requirements of TRL 3 and below, except that the testing is conducted in a relevant environment (simulated or actual) over its full operating range. |
| | TRL 5 | System Integration Tested (prototype integrated with intended system and functionally tested) | At TRL 5, the technology meets all of the requirements of TRL 4 and below and is integrated into its intended operating system and tested. The testing includes full interface and functional testing. The system integration test environment may not be field realistic. (This TRL may not be applicable for all technology.) |
| Field Qualified | TRL 6 | Technology Deployed (prototype deployed in field test or actual operation) | At TRL 6, the technology has been developed into a field-ready prototype or production unit and has been integrated into its intended operating system and installed in the field. The technology has successfully operated for <10% of its expected life. |
| | TRL 7 | Proven Technology (production unit success-fully operational for >10% of expected life) | At TRL 7, the technology is now in production and has been fully integrated into its intended operating system and installed in the field. The technology has successfully operated with acceptable performance and reliability for >10% of its specified life. |

# APPENDIX C – EXAMPLE TEMPLATE OF FUTURE-BASED SOFTWARE MODELING TOOL

| Components for Reservoir Well Testing Systems | System 1 | System 2 | System 3 | System 4 | System 5 | System 6 | System 7 | System 8 |
|---|---|---|---|---|---|---|---|---|
| | Standard deep water MODU, drilling riser, subsea BOPs, production facilities and oil storage on the MODU (usually used for short term tests). | Standard deep water MODU, drilling riser, surface BOPs, production facilities and oil storage on the MODU | Standard deep water MODU, drilling riser, use with System 1 (subsea BOP) or System 2 (surface BOP), production facilities and oil storage NOT on the MODU. | Seillean type system where the vessel has the ability to run a production riser, connect and disconnect to subsea production tree, treat the produced fluids and store the oil or transfer the oil to another storage. | This testing system connects the production tree via flexible pipe to a vessel that processes the fluids and either stores the fluids or transfers the fluids to another storage vessel, requires some type of intervention vessel to run and retrieve the flexible line, and to do any intervention done to the well by a MODU or intervention type vessel. Assumes all controlling of the subsea tree is from the primary production vessel. | This system uses an intervention vessel or MODU to connect to the subsea production tree via a production riser where the intervention vessel or MODU can intervene through the production tree to the well, i.e., re-complete, pull tubing, run special down hole equipment. | This testing system uses a self standing riser (SSR) that connects to production tree and produces either through the riser (single barrier) or through a tie back liner in the riser (double barrier). The SSR is either installed by an intervention vessel or special designed vessel to run the riser. Any MODU or intervention vessel can intervene through the production tree to the well. Production goes to an FPU/storage vessel or an FPSO. | Consists of SSR connected to sea floor with a suction anchor. Only used when subsea production tree will not support an SSR. Any work on the well must be done by an intervention vessel or MODU. |
| **Technical Readiness Level Ratings:** | TRL Level 7.00 | TRL Levels 6.64 | Subsea - TRL Level 6.93<br>Surface - TRL Levels 4.64 | TRL Levels 6.79 | TRL Levels 5.29 | TRL Level 7.00 | TRL Levels 4.79 | TRL Levels 6.93 |
| MODU - (Semi-submersible or Drillship) | Yes | Yes | Yes | | | Yes | Yes | Yes |
| MODU- capable of handling flexible riser | | | | | | | Yes | Yes |
| Multi-support Vessel (MSV - ex. Heavy duty | | | | | | Yes | | |
| Floating Production Vessel (FPU) | | | Yes | | Yes | | | |
| Seillean-like vessel (FPSO with or without drilling capability) | | | | Yes | | | | |
| Floating Production Storage Offloading Vessel (FPSO) | | | | | Yes | | | |
| Well Intervention Vessel (WIV) | | | | | | Yes | | |
| Multipurpose Support Vessel (MSV) to install & | | | | | Yes | | Yes | Yes |
| | | | | | | | | |
| Dynamic Positioning (DP) Mooring System | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Anchor Moored System (Alternative to DP System) | Yes | Yes | MODU Yes FPU No | Yes | FPU/FPSO Yes MSV No | MODU Yes WIV No | MODU Yes MSV No | MODU Yes MSV No |
| Helicopter Deck | Yes | Yes | Yes | Yes | FPU/FPSO Yes MSV Optional | Yes | FPU/FPSO Yes MSV Optional | FPU/FPSO Yes MSV Optional |
| Motion Compensating System - Riser Installation | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Motion Compensating System - Production | Yes | Yes | Yes | | | Yes | | |
| Riser (Rigid) Tensioning System | Yes | Yes | Yes | Yes | | Yes | | |
| Surface Flow Head | Yes | Yes | Yes | Yes | | | | |
| Surface Test Tree | | Yes | | | | | | |
| Surface Production Shutoff Device | | | | | Yes | | Yes | Yes |
| Surface BOP | | Yes | | | | | | |
| Marine Riser Handling System | Yes | Yes | MODU #1 Yes<br>MODU #2 N/A | | | | Yes | Yes |
| Rigid Riser Handling System | Yes | Yes | Yes | Yes | | Yes | | |
| Flexible Riser Handling System | | | | | Yes | | Yes | Yes |
| Production Fluid Offloading Transfer System | | | Yes | | | | | |
| Telescopic Slip Joint (low pressure) | Yes | Yes | Yes | | | | | |
| Marine 21 " Riser w/high pressure kill, choke, booster, hydraulic lines | Yes | | MODU #1 Yes<br>MODU #2 N/A | | | | | |
| Multiplex Subsea (BOP) Control System (MUX) | Yes | Yes | Yes | Yes | | Yes | | |
| Acoustic Subsea (BOP) Control System | Optional | | MODU #1 Optional<br>MODU #2 N/A | Optional | | Optional | | |

| | System 1 | System 2 | System 3 | System 4 | System 5 | System 6 | System 7 | System 8 |
|---|---|---|---|---|---|---|---|---|
| Subsea BOP stack (LMRP & BOP) | Yes | | MODU #1 Yes<br>MODU #2 N/A | | | Yes | | |
| Subsea Test Tree (SSTT) | Yes | | MODU #1 Yes<br>MODU #2 N/A | | | Yes | | |
| SSTT Emergency Disconnect | Yes | | MODU #1 Yes<br>MODU #2 N/A | | | Yes | | |
| LMRP (Lower Marine Riser Package) Emergency Disconnect (EDS) | Yes | | MODU #1 Yes<br>MODU #2 N/A | | | | | |
| Wellhead | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| High-Pressure 13-3/8 in Casing Riser | | Yes | MODU #2 Yes<br>MODU #1 N/A | | | | | |
| Seafloor Shutoff Assembly (SSA) | | Yes | MODU #2 Yes<br>MODU #1 N/A | | | | | |
| SSA Multiplex Control System (MUX) | | Yes | MODU #2 Yes<br>MODU #1 N/A | | | | | |
| SSA Acoustic Control System | | Yes | MODU #2 Yes<br>MODU #1 N/A | | | | | |
| SSA (Casing Riser) Emergency Disconnect (EDS) | | Yes | MODU #2 Yes<br>MODU #1 N/A | | | | | |
| High-Pressure Drill Pipe Riser 6-5/8" | | | | Yes | | | | |
| Seillean-Like Emergency Disconnect Package (EDS) | | | | Yes | | | | |
| Seillean-Like Lower Workover Riser Package | | | | Yes | | | | |
| Subsea tree | No | No | No | Yes Vertical | Yes Horizontal | Yes | Yes | Yes |
| High Pressure Flexible Riser | | | | | Yes | | Yes | Yes |
| Block Valve | | | | | Yes | | | |
| Buoyancy Element | | | Yes | | Yes | | | |
| Pipeline End Termination (PLET) | | | | | Yes | | | |
| Lubricator Valve inside Drilling Riser | | | | | Yes | | | |
| Low Pressure Drilling Riser | | | | | Yes | | | |
| Production Riser | | | | | Yes | | | |
| Centralizer | | | | | Yes | | | |
| Retainer Valve | | | | | Yes | | | |
| Shear Sub | | | | | Yes | | | |
| Buoyancy Chamber/Module | | | | | Yes | | Yes | Yes |
| Circulation Head | | | | | | | Yes | Yes |
| Self-Standing Riser (SSR) | | | | | | | Yes | Yes |
| Seafloor Shutoff Device (SSD) | | | | | | | Yes | Yes |
| SSD Multiplex Control System (MUX) | | | | | | | Yes | Yes |
| High Pressure Flexible Flowline | | | | | | | | Yes |
| Remotely Operated Vehicle (ROV) Support | Yes | Yes | Yes | Yes | Yes | Yes | Yes | Yes |